STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1187

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-7, SUB 1213 In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program DOCKET NO. E-7, SUB 1214 In the Matter of Application by Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina DOCKET NO. E-7, SUB 1187 In the Matter of Application of Duke Energy Carolinas, LLC for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego	)	ORDER ACCEPTING STIPULATIONS, GRANTING PARTIAL RATE INCREASE, AND REQUIRING CUSTOMER NOTICE

HEARD: Wednesday, January 15, 2020, at 7:00 p.m., in Courtroom A, Macon County Courthouse, 5 West Main Street, Franklin, North Carolina

Thursday, January 16, 2020, at 7:00 p.m., in the Burke County Courthouse, 201 South Green Street, Morganton, North Carolina

Wednesday, January 29, 2020, at 7:00 p.m., in the Alamance County Historic Courthouse, 1 SE Court Square, Graham, North Carolina

Thursday, January 30, 2020, at 7:00 p.m., in Courtroom 5350, Mecklenburg County Courthouse, 832 East 4th Street, Charlotte, North Carolina

Monday, August 24, 2020, at 2:00 p.m., held via video conference, and reconvened on Thursday, September 3, 2020, at 9:00 a.m., via video conference

BEFORE: Chair Charlotte A. Mitchell, Presiding; and Commissioners ToNola D. Brown-Bland, Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes, and Floyd B. McKissick, Jr.

APPEARANCES

For Duke Energy Carolinas, LLC:

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For Carolina Industrial Group for Fair Utility Rates III:

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For Carolina Utility Customers Association, Inc.:[1]

Robert F. Page, Crisp & Page, PLLC, 4010 Barrett Drive, Suite 205, Raleigh, North Carolina 27609

[1] On January 12, 2021, the Commission granted the motion of Mr. Page, Marcus Trathen, and Craig Schauer to allow Mr. Page to withdraw as CUCA's counsel and to substitute Mr. Trathen and Mr. Schauer as counsel for CUCA.

For North Carolina Sustainable Energy Association:

Peter H. Ledford, General Counsel, and Benjamin Smith, Regulatory Counsel, North Carolina Sustainable Energy Association, 4800 Six Forks Road, Suite 300, Raleigh, North Carolina 27609

For Vote Solar:

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For Sierra Club:

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For the Commercial Group:

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For Apple Inc., Facebook, Inc., and Google LLC:

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For North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy:

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For Harris Teeter LLC:

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North Carolina Clean Energy Business Alliance:

Karen Kemerait, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For North Carolina League of Municipalities:

Deborah Ross, Fox Rothschild LLP, 434 Fayetteville Street, Suite 2800, Raleigh, North Carolina 27601

For Center for Biological Diversity and Appalachian Voices:

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For the Using and Consuming Public:

Dianna W. Downey, Chief Counsel; and Elizabeth D. Culpepper, Layla Cummings, Tim R. Dodge, Lucy E. Edmondson, William E. Grantmyre, Gina C. Holt, Megan Jost, John D. Little, and Nadia L. Luhr, Staff Attorneys, Public Staff–North Carolina Utilities Commission, 4326 Mail Service Center, Raleigh, North Carolina 27699-4300

Teresa Townsend, Special Deputy Attorney General, and Margaret A. Force, Assistant Attorney General, North Carolina Department of Justice, Post Office Box 629, Raleigh, North Carolina 27603

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BY THE COMMISSION: On August 29, 2019, pursuant to Commission Rule R1-17(a), Duke Energy Carolinas, LLC (DEC or Company), filed notice of its intent to file a general rate case application.

On September 30, 2019, DEC filed an Application to Adjust Retail Rates and Request for an Accounting Order (Application), along with the required Rate Case Information Report, Form E-1 (Form E-1), and the direct testimony and exhibits of numerous witnesses.

PROCEDURAL HISTORY AND JURISDICTION

Procedural History

The Commission has issued a multitude of procedural orders in these dockets, all of which are a matter of record herein. The following is a summary of the most pertinent filings by the parties and the Commission's procedural orders.

On various dates petitions to intervene were filed by the following parties and were granted by orders of the Commission: Carolina Industrial Group for Fair Utility Rates III (CIGFUR); Carolina Utility Customers Association, Inc. (CUCA); North Carolina Sustainable Energy Association (NCSEA); Vote Solar; Sierra Club; Center for Biological Diversity and Appalachian Voices (CBD/AV); North Carolina Waste Awareness and Reduction Network (NC WARN); Commercial Group; Apple Inc., Facebook, Inc., and Google LLC (collectively, the Tech Customers); North Carolina Justice Center (NCJC), North Carolina Housing Coalition (NCHC), Natural Resources Defense Council (NRDC), and Southern Alliance for Clean Energy (SACE; together with NCJC, NCHC, and NRDC, NCJC et al.); Harris Teeter LLC; North Carolina Clean Energy Business Alliance (NCCEBA); and North Carolina League of Municipalities (NCLM). In addition, a Notice of Intervention was filed by the North Carolina Attorney General's Office (AGO). The Public Staff's intervention is recognized pursuant to N.C. Gen. Stat. § 62-15(d) and Commission Rule R1-19(e).

On October 29, 2019, the Commission issued an Order Establishing General Rate Case, Suspending Rates, Scheduling Hearings, and Requiring Public Notice (Scheduling Order).

On November 20, 2019, the Commission issued an order consolidating DEC's petition for approval of its Prepaid Advantage Program in Docket No. E-7, Sub 1213 with DEC's rate case.

In January 2020, the Commission held four public hearings as scheduled by the Commission's October 29, 2019 Order for the purpose of receiving the testimony of public witnesses.

On February 18, 2020, the Public Staff and numerous other parties filed the direct testimony and exhibits of their witnesses.

On March 4, 2020, DEC filed the rebuttal testimony and exhibits of several witnesses.

The expert witness hearing in this matter was initially set to commence on March 23, 2020. However, due to the novel coronavirus (COVID-19) pandemic and the declared State of Emergency issued by Governor Roy Cooper, on March 16, 2020, the Commission issued an order postponing the expert witness hearing until further order of the Commission and accepting DEC's prospective waiver of its right to implement its original proposed rates by operation of N.C.G.S. § 62-134(b).

On March 25, 2020, DEC and the Public Staff filed their Agreement and Stipulation of Partial Settlement (First Partial Stipulation).

On May 6, 2020, DEC, Duke Energy Progress, LLC (DEP), and the Public Staff filed a motion to consolidate for hearing DEC's Application and DEP's application for a rate increase filed in Docket No. E-2, Sub 1219 (DEP Application). Their motion stated that many of the issues in the two general rate case proceedings were based on substantially similar testimony and that efficiencies could be gained by consolidating the expert witness hearings for DEC and DEP (collectively, the Companies), particularly in light of logistical challenges related to the COVID-19 State of Emergency.

On June 17, 2020, the Commission issued an order revising the schedule for the DEC expert witness hearing and consolidating the DEC hearing with the expert witness hearing in the DEP Application on several topics, with the hearing to be held remotely by video conference.

On June 22, 2020, DEC filed a Petition for an Accounting Order to Defer Impacts of Its Suspended Rate Case in Lieu of Implementing Temporary Rates Under Bond requesting to defer the revenue impacts of the postponement of the expert witness hearing.

On June 26, 2020, the Commission entered an order consolidating DEC's rate case and Prepaid Advantage Program dockets with the Company's application in Docket No. E-7, Sub 1187 for an accounting order to defer incremental storm damage expenses incurred as a result of Hurricanes Florence and Michael and Winter Storm Diego.

On July 9, 2020, the Commission issued an order denying DEC's Petition for an Accounting Order.

On July 24, 2020, DEC filed a Motion for Approval of Notice Required by N.C. Gen. Stat. § 62-135 to Implement Temporary Rates, Subject to Refund, and Authorization of EDIT Rider together with a Motion for Approval of Undertaking Required by N.C.G.S. § 62-135(c) to Implement Temporary Rates, Subject to Refund. The Commission issued an order on August 6, 2020, approving DEC's financial undertaking and proposed public notice of temporary rates.

On July 31, 2020, DEC and the Public Staff filed their Second Agreement and Stipulation of Partial Settlement (Second Partial Stipulation).

On August 10, 2020, the Commission issued an order scheduling a separate expert witness hearing on DEC's Application to address issues that would not be addressed in the DEC/DEP consolidated hearing.

On August 24, 2020, the matter came on for the consolidated expert witness hearing. Testimony and exhibits were presented for DEC, DEP, and several parties on financial issues, including cost of capital, capital structure, and credit quality, as well as Excess Deferred Income Taxes (EDIT), Grid Improvement Plan (GIP), and rate affordability. The DEC-specific (nonconsolidated) expert witness hearing commenced on September 3, 2020, and DEC and the parties presented testimony and exhibits on numerous additional issues.

In accordance with orders of the Commission, several parties submitted post-hearing briefs and proposed orders on November 4, 2020.

On January 25, 2021, the Companies, the Public Staff, the AGO, and Sierra Club (collectively, CCR Settling Parties) filed the Coal Combustion Residuals (CCR) Settlement Agreement (CCR Settlement) in these dockets and in the dockets in which the DEP Application is pending.

On January 29, 2021, DEC filed the testimony and exhibits of several witnesses supporting the CCR Settlement; DEC filed correction to certain of that testimony on February 1, 2021. Also on January 29, 2021, the CCR Settling Parties filed a Joint Motion to Reopen Record, Consolidate Consideration of CCR Settlement Agreement, and for Approval of CCR Settlement Agreement.

On February 5, 2021, the Public Staff filed the testimony and exhibits of several witnesses supporting the CCR Settlement.

On February 12, 2021, the Commission issued an Order Reopening Records, Allowing Testimony or Comments on Proposed Settlement, and Allowing Requests for Hearing. No such testimony or comments were filed by any party, and no party requested a hearing.

Lastly, on February 17, 2021, the Commission issued an Order Requiring Responses to Commission Questions specifically related to the CCR Settlement, responses to which were filed by the Companies on February 23, 2021.

Jurisdiction

No party has contested the fact that DEC is a public utility subject to the Commission's jurisdiction pursuant to the Public Utilities Act, Chapter 62 of the North Carolina General Statutes. The Commission concludes that it has personal jurisdiction over DEC and subject matter jurisdiction over the matters presented in DEC's Application.

Application

In summary, DEC requested in its September 30, 2019 Application an annual North Carolina retail base rate increase of approximately $445.3 million, an approximately 9.2% increase over its current North Carolina retail base rates. DEC also proposed to return to ratepayers approximately $154.6 million annually of EDIT.

In its Application, DEC stated that its need for a rate increase is driven primarily by costs of improving the reliability and safety of its operations, costs of restoring service after Hurricanes Florence and Michael and Winter Storm Diego, costs of coal ash remediation, an increase in depreciation expense due to accelerated retirement dates for coal-fired generation units, and upgrades to generating plants and transmission assets. DEC witnesses testified that the appropriate test period in this case is the 12 months ended December 31, 2018, with updates to costs, revenues, and rate base through May 31, 2020. As a result of the updates to DEC's costs, revenues, and rate base, on July 2, 2020, DEC revised its requested rate increase to approximately $414.5 million.

Pursuant to the authority granted to public utilities under N.C.G.S. § 62-135 to implement temporary rates, subject to refund, on August 24, 2020, DEC implemented temporary rates pending a final order in this proceeding.

Whole Record

The Commission held four public witness hearings, as noted above. The following public witnesses appeared and testified:

Franklin: Victoria Estes, Elsa Enstrom, Patricia Bailey, Al Bernard, William Thomas, Callie Moore, Tamara Zwinak, Pat McGee, Katie Breckheimer, and Debra Uccetta

Morganton: Rory McIlmoil, Henry Belada, Phil Bisesi, Chris Kanipe, Matt Wasson, and Jeff Deal

Graham: Beth McKee-Huger, Carolina Armijo, Deborah Graham, Harry Phillips, Leonard Williams, John Merrell, Bobby Jones, Ron Namest, Heather Sanchez, Rachel Velez, Linda Nelson, Anne Cassebaum, Timothy Greene, Carole Troxler, Peggy Wilson, Herald Voss, Jillian Riley, John Loftis, Harry Clapp, Abigail Rosenthal, John Wagner, John Martin, Deborah Smith, Joseph Alston, and Wendy Wilson

Charlotte: Steve Allinger, Nicholas Rose, Steve Copulsky, Kenneth Kneidel, Dave Walsh, Sally Kneidel, Beth Henry, Kent Moore, Kent Crawford, Holli Adams, Tina Katsanos, Dennis Testerman, Maya Wells, Andrew Goff, Jim Backman, Allen Smit h, Shawn Richardson, Louri Fox, Lucas Blanco, Nancy Carter, Jerome Wagner, Nancy Duncan, Cate De Mallie, John Hudspeth, Bethany Menut, Katherine Sparrow, Ricardo Arevalo, Doug Swaim, Kate Lewin, and Corbin Steele

In summary, almost all the public witnesses stated their opposition to DEC's proposed rate increase. *See generally*, tr. vols. 1-4. Many witnesses testified that they were on fixed incomes and about the poverty in some of the counties served by DEC. They specifically mentioned high medical bills, student debt, lost pensions, and displaced workers as causes of poverty and difficulty in paying electric bills. In addition, many public witnesses stated concerns about coal ash, including the health effects on people located in proximity to coal ash basins and contamination of water supplies. Further, witnesses expressed their view that it is unfair for the cost of the coal ash cleanup to burden ratepayers rather than coming out of the Company's or shareholders' profits. They also spoke of the insurance companies not paying for the coal ash cleanup costs. Moreover, public witnesses testified to their concerns regarding DEC's use of fossil fuels, including coal and natural gas power plants, fracking, and DEC's not adequately increasing the use of clean energy and renewables. Some witnesses connected these concerns with the increased effects of hurricanes, storm recovery, and the proposed Atlantic Coast Pipeline. Finally, some public witnesses voiced their view that DEC's executive compensation and shareholder dividends are excessive.

In addition to the public witness testimony, the Commission received numerous written consumer statements of position, all of which were filed in the docket. *See generally*, Docket No. E-7, Sub 1214CS. The public witness testimony and consumer statements of position have been considered by the Commission in its deliberations on DEC's rate case Application.

In the Scheduling Order the Commission took judicial notice pursuant to N.C.G.S. § 62-65 of all evidence, decisions, and matters of record on the issues of coal ash remediation, Power Forward, and Advanced Metering Infrastructure (AMI) in DEC's last general rate case, Docket No. E-7, Sub 1146 (Sub 1146). Said evidence, decisions, and matters of record were accepted into evidence in the present docket and are hereby incorporated by reference into this Order. The judicially noticed evidence will not be repeated in full or summarized, but portions of the testimony and exhibits are referenced throughout this Order.[2]

The testimony and exhibits in this proceeding are voluminous. The Commission has carefully considered all of the evidence and the record as a whole. However, the Commission has not attempted to recount every statement of every witness in this Order. Rather, the Commission has summarized the evidence that is in the record. Likewise, while the Commission has read and fully considered the parties' post-hearing briefs, it has not in this Order attempted expressly to summarize or discuss every contention advanced or authority cited in the briefs.

[2] The form of the transcript reference in this Order for the Sub 1146 evidence is, for example, "2018 Tr. vol. 8, 209." The form of the exhibits reference for the Sub 1146 exhibits is, for example, "2018 Public Staff Maness Direct Ex. 4." Additionally, the form of the transcript reference in this Order for the consolidated hearing held August 24, 2020, through August 31, 2020, is, for example, "Consolidated Tr. vol. 3, 194," and the exhibits reference is, for example, "Consolidated DEC Pirro Rebuttal Ex. 2."

Based upon the foregoing and the entire record in this proceeding the Commission makes the following

FINDINGS OF FACT

Stipulations

1. On March 25, 2020, DEC and the Public Staff filed the First Partial Stipulation resolving some of the issues between the two parties, and on July 31, 2020, the Public Staff and DEC filed the Second Partial Stipulation resolving several additional issues.

2. On various dates during this proceeding, DEC entered into and filed stipulations and amendments thereto with Harris Teeter (HT Stipulation), Commercial Group (CG Stipulation), CIGFUR (CIGFUR Stipulation), and Vote Solar (Vote Solar Stipulation), and entered into and filed a joint stipulation with NCSEA and NCJC et al. (NCSEA/NCJC et al. Stipulation), each of which resolved some of the issues in this proceeding between DEC and these parties.

3. The stipulations with the Public Staff, Harris Teeter, Commercial Group, CIGFUR, Vote Solar, NCSEA, and NCJC et al. are products of the give-and-take settlement negotiations between DEC the respective parties.

Base Fuel and Fuel-Related Cost Factors

4. Consistent with Section IV.N of the Second Partial Stipulation, the total base fuel and fuel-related cost factors, by customer class, represented by the sum of the respective base fuel and fuel-related costs factors set in Sub 1146 and the annual non-EMF fuel and fuel-related costs riders approved in Docket No. E-7, Sub 1228 (Sub 1228) are just and reasonable to all parties.

Amortization of Loss on Hydro Station Sale

5. Amortization of the Company’s loss on the sale of hydro stations over the overall remaining depreciable life of the assets of 20 years reasonably spreads the loss on sale over the years in which customers would have otherwise received service from the hydro stations.

6. It is just and reasonable to adopt the 20-year amortization period for the Company’s loss on the sale of hydro stations recommended by the Public Staff as opposed to the seven-year period recommended by the Company.

7. It is appropriate for DEC to earn a return on the unamortized balance related to the loss on the sale of hydro stations.

Depreciation Study

8. Use of a 10% contingency for future “unknowns” in the estimate of future terminal net salvage costs is reasonable.

9. Use of an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346 is reasonable.

10. Use of escalation of terminal net salvage cost and the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study is reasonable.

11. Use of the Company’s proposed future net salvage for mass property Account 366, Underground Conduit, is reasonable.

12. Use of an average service life of 15 years for the new AMI meters is reasonable.

13. Except where specifically addressed in this Order, the depreciation rates proposed by DEC, which are based on the Depreciation Study filed by the Company as Spanos Direct Exhibit 1 and the Decommissioning Cost Estimate Study filed by the Company as Doss Direct Exhibit 4 in Sub 1146, are just and reasonable.

Early Retirement of Coal Plants

14. The integrated resource planning (IRP) proceeding is the appropriate proceeding for a thorough review of generating plant retirements.

15. The depreciation rates for the Allen Units 4 and 5 and Cliffside Unit 5 generating plants should be based upon the remaining lives of the plants.

Alleged Uneconomical Coal Plant Costs

16. DEC’s investments in its coal fleet were reasonably and prudently incurred to enable DEC to meet its obligation to provide safe, adequate, and reliable electric service.

17. It is not necessary or appropriate to impose a limit on DEC’s future investments in its coal-fired generating assets.

18. DEC’s costs associated with the Belews Creek Unit 1 dual fuel optionality (DFO) project resulted in used and useful property and should be recovered.

CCR Cost Recovery

19. North Carolina enacted the Coal Ash Management Act (CAMA) in 2014, which was amended in 2016, and the United States Environmental Protection Agency

(EPA) promulgated its final rule, the Coal Combustion Residuals Rule (CCR Rule), in 2015. Together, these state and federal laws and regulations introduced new requirements for the management of coal ash and mandated the closure of the coal ash basins at all of the Company's coal-fired power plants.

20. Since its last rate case, DEC has incurred significant additional costs to continue the closure and compliance efforts related to these federal and state legal requirements and its management and storage of CCR. On a North Carolina retail jurisdictional basis, as of July 31, 2020, the CCR costs DEC incurred for which it seeks recovery in this rate case amount to $378,464,403, $341,658,176 of which are the actual deferred coal ash basin closure and compliance costs incurred by the Company during the period from January 1, 2018, through January 31, 2020, and the remaining $36,806,227 of which are the financing costs incurred by the Company upon the deferred costs through July 2020.

21. The January 25, 2021 CCR Settlement, which is the product of give-and-take settlement negotiations in resolving the issues among the CCR Settling Parties related to CCR cost recovery, is material evidence in this proceeding and is entitled to be given appropriate weight in this proceeding along with other evidence adduced by the Company and intervenor parties.

22. Section III.E of the CCR Settlement provides that the amount of CCR costs and financing costs sought for recovery in this case will be reduced by $224 million. Additionally, Section III.E provides for the recovery of financing costs sought for recovery in this case during the deferral period, calculated at the weighted average cost of capital, as well as during a five-year amortization period, calculated using: (1) DEC's cost of debt as previously stipulated by the Company and the Public Staff in the Second Partial Stipulation adjusted as appropriate to reflect the deductibility of interest expense; (2) a cost of equity 150 basis points below the 9.60% stipulated to in the Second Partial Stipulation; and (3) a 48% debt and 52% equity capital structure.

23. Section III.F of the CCR Settlement provides that the amount to be recovered of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, along with associated financing costs incurred during the deferral period, will be reduced by $108 million but allows for recovery of any remaining CCR costs, subject to determination by the Commission that such costs were reasonably and prudently incurred. Additionally, Section III.F provides for recovery of financing costs during the applicable deferral period, calculated at the weighted average cost of capital, and provides for recovery of financing costs during the applicable amortization period, calculated using a reduced cost of equity.

24. Section III.D.i of the CCR Settlement provides that the CCR Settling Parties waive their right to assert that future CCR costs should be shared between the Company and ratepayers through equitable sharing of the costs or other adjustment except as provided in the CCR Settlement. Section III.D.ii provides that the CCR Settling Parties waive their right to challenge future CCR costs on the basis that the Company's historical coal ash management practices were inadequate and led to unreasonable CCR costs

being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. Section III.D.iii of the CCR Settlement provides that the CCR Settling Parties reserve their right to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

25. Section III.G of the CCR Settlement provides for an allocation between the Companies and their customers of any proceeds from ongoing coal ash insurance litigation.

26. The provisions of the CCR Settlement are just and reasonable in light of all of the evidence presented. It is appropriate for the Company to reduce the balance of deferred CCR costs sought to be recovered in this rate case by $224 million. It is appropriate that the $224 million reduction reduce the deferred CCR costs as of December 31, 2020, and that DEC cease to accrue financing costs on that amount after December 31, 2020, and not seek to recover such financing costs from customers, as set forth in Section E of the CCR Settlement. After such reduction and updating financing costs through June 2021, the net amount for which the Company seeks recovery in this case is $169,528,066. It is further appropriate for the Company to defer CCR costs incurred since February 1, 2020, and to reduce the balance of deferred CCR costs sought to be recovered in its next general rate case by $108 million as set forth in Section III.F of the CCR Settlement. It is appropriate that no financing costs accrue on the $108 million as of December 31, 2020, as set forth in Section III.F of the CCR Settlement. The reduced financing costs agreed upon in Sections III.E and III.F of the CCR Settlement are appropriate.

ARO Accounting

27. DEC is required to comply with Generally Accepted Accounting Principles (GAAP), specifically, Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410), and ASC 980, Regulated Operations.

28. DEC is required to comply with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA), specifically, General Instruction No. 25, Accounting for Asset Retirement Obligations.

29. Neither GAAP nor FERC accounting drives cost recovery for North Carolina retail ratemaking purposes; rather, the ratemaking treatment determined by the Commission drives financial accounting.

Capital Structure, Cost of Capital, and Overall Rate of Return

30. As set forth in Section III.B of the Second Partial Stipulation, the Public Staff and the Company agreed on a capital structure consisting of 52% common equity and 48% long-term debt.

31. The Company’s embedded cost of debt is 4.27%, as set forth in Section III.B of the Second Partial Stipulation.

32. As set forth in Section III.B of the Second Partial Stipulation, the Company and the Public Staff agreed that the Company should be allowed the opportunity to earn a rate of return on common equity (ROE) of 9.60%.

33. The overall rate of return that the Company should be allowed the opportunity to earn on the cost of the Company's used and useful property is 7.04%.

34. The overall rate of return and ROE are supported by competent, material, and substantial evidence; are consistent with the requirements of N.C.G.S. § 62-133 in light of changing economic conditions; and appropriately balance the Company's need to maintain the safety, adequacy, and reliability of its service with the benefits received by DEC's customers from safe, adequate, and reliable electric service.

35. The capital structure, ROE, and overall rate of return set by this Order will result in just and reasonable rates.

Cost of Service Adjustments

36. The agreed-upon accounting adjustments outlined in McManeus Supplemental Rebuttal Exhibit 3, McManeus Second Settlement Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1 (Partial Stipulation Revenue Requirement Exhibits) are just and reasonable to all parties in light of all the evidence presented.

Deferral of Grid Improvement Plan Capital Costs

37. DEC requested deferral of approximately $1.3 billion in spending to occur from January 2020 through 2022 on its GIP.

38. As a result of DEC's Second Partial Stipulation with the Public Staff and settlements with other parties, DEC narrowed the scope of the programs for which the Company seeks capital cost deferral and reduced its request to approximately $800 million in GIP spending from June 2020 through 2022.

39. DEC's reduced GIP deferral request as set forth in the Second Partial Stipulation is reasonable and should be approved subject to limitation.

40. DEC has the burden of proving that its GIP spending is reasonable and prudent when it seeks to recover, in any future proceeding, GIP costs from customers.

41. GIP expenditures beyond those covered by the GIP deferral approved herein are to be informed by the Integrated System Operations Planning (ISOP) process.

Tax Act Issues

42. Federal protected EDIT should be removed from DEC's proposed rider and amortized through base rates in accordance with the Internal Revenue Service (IRS) normalization rules as DEC agreed in the First Partial Stipulation.

43. The federal unprotected EDIT should be flowed back to customers using a levelized five-year rider as DEC agreed in the Second Partial Stipulation.

44. The federal provisional revenues should be flowed back to customers using a levelized two-year rider as DEC agreed in the Second Partial Stipulation.

45. State EDIT should be flowed back to customers using a levelized two-year rider as DEC agreed in the Second Partial Stipulation.

46. The provisions of the CIGFUR Stipulation regarding the appropriate methodology to flow back unprotected EDIT and provisional revenues are not just and reasonable and should not be approved.

47. All federal unprotected EDIT and provisional revenues should be refunded to customers using the methodology based on the amounts each class paid, and specifically, as a credit by specific customer class divided by the adjusted class' test year sales, as recommended by Public Staff witness Floyd.

48. The agreement between DEC and the Public Staff in the Second Partial Stipulation concerning how to address changes in the federal corporate income tax rate and the North Carolina state corporate income tax rate which may occur during the respective amortization periods is reasonable and appropriate.

Cost Allocation Methodology

49. In the Second Partial Stipulation the Company and the Public Staff agreed to calculate and allocate the Company's cost of service based on a Summer Coincident Peak (SCP) cost-of-service methodology to determine the Company's North Carolina jurisdictional and retail customer class cost allocation and responsibility.

50. As set forth in the CIGFUR Stipulation, the Company has committed to file in its next general rate case the results of a class cost-of-service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and to consider such results for the sole purpose of apportionment of the change in revenue to the customer classes.

Rate Design

51. It is appropriate for the Company to conduct a comprehensive rate design study as agreed to in the Second Partial Stipulation and expanded on in this Order.

Affordability

52. It is appropriate for the Company to convene a stakeholder process tasked with addressing affordability issues for low-income residential customers as DEC agreed in the NCSEA/NCJC et al. Stipulation and the Second Partial Stipulation.

53. It is appropriate for the Company to provide, in conjunction with the concurrent commitment of DEP, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million) which will not affect rates as DEC agreed in the NCSEA/NCJC et al. Stipulation.

54. It is appropriate for the Company to make an annual $2.5 million shareholder contribution to the Share the Warmth Fund in 2021 and 2022 (for a total of $5 million) which will not affect rates as DEC agreed in the Second Partial Stipulation.

Storm Costs

55. The costs incurred by DEC to respond to Hurricanes Florence and Michael and Winter Storm Diego (Storm Costs) as presented by the Company and agreed to in the First Partial Stipulation are just and reasonable and were prudently incurred to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward remain subject to review pursuant to the provisions of N.C.G.S. § 62-172(a)(14)(c).

56. DEC's Storm Costs total $213.1 million, consisting of approximately $169.8 million in actually incurred or projected storm response operations and maintenance (O&M) costs, approximately $18.6 million in capital investments, and approximately $24.7 million in carrying costs calculated using the Company's approved weighted average cost of capital through July 31, 2020.

57. Consistent with the First Partial Stipulation and the testimony of witness De May, DEC has withdrawn the Storm Costs, including capital investments, from the current rate case, except for purposes of the prudence determination reached in Finding of Fact No. 55.

58. It is appropriate that DEC continue to defer the Storm Costs in a regulatory asset account until the date storm cost recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172 or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery.

59. It is appropriate that DEC continue to accrue and record carrying costs at the Company's approved weighted average cost of capital on the deferred balances in its storm cost recovery deferral account pending recovery through securitization, subject to the assumptions and conditions agreed to in the First Partial Stipulation.

60. A ten-year normalized adjustment to DEC's revenue request to account for anticipated storm expenses that are too small to securitize is appropriate for use in this proceeding.

61. It is appropriate to establish a Storm Cost Recovery Rider for the Company and to set the initial balance for that rider at $0 in conformance with the provisions of the First Partial Stipulation.

Adjustments to Plant in Service

62. The capital costs associated with the Lincoln County Combustion Turbine 17 (LCCT 17) project should be removed from the rate base.

63. The capital costs associated with Project Focal Point 12 should be removed from rate base.

Prepaid Advantage Program

64. The Company's proposed Prepaid Advantage Program, with conditions as set forth herein, is reasonable and in the public interest.

AMI and Green Button Connect

65. DEC's costs of deploying AMI meters were prudently incurred and are reasonable.

66. It is appropriate for DEC to recover from all customers Rider MRM costs not recovered from customers opting out of AMI meters.

67. The question of whether DEC should implement Green Button "Connect My Data" should be addressed in the ongoing investigation and rulemaking in Docket No. E-100, Sub 161.

Service Regulations, Vegetation Management, and Quality of Service

68. The amendments to the service regulations proposed by the Company are reasonable and should be approved.

69. DEC's annual target for distribution system vegetation management has increased from 6,177 to 6,187 miles. DEC's annual target for distribution system vegetation management of 6,187 miles is an increase from the 5,559 miles trimmed in the test year. DEC's outside labor expense for vegetation management contract work has increased by 3%. It is therefore appropriate to adjust DEC's vegetation management annual expense for these factors, subject to the Public Staff's corrected cost per mile adjustment.

70. With the adjustment in Finding of Fact No. 69, DEC's vegetation management plan is reasonable.

71. The overall quality of service provided by DEC is good.

Accounting for Deferred Costs

72. The Company is authorized to receive a specific amount of revenue for each of the deferred costs approved by this Order. If DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case.

Just and Reasonable Rates

73. The base non-fuel and base fuel revenues and rates approved herein are just and reasonable for the customers of DEC, DEC, and all parties to this proceeding, and serve the public interest.

Revenue Requirement

74. After giving effect to the portions of the settlement agreements approved herein and the Commission's decisions on contested issues, the annual revenue requirement for DEC will allow the Company a reasonable opportunity to recover its operating costs and earn the rate of return on its rate base that the Commission has found to be just and reasonable.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1–3

Stipulations

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the stipulations between DEC and other parties, the testimony and exhibits of DEC witness De May and Public Staff witness Boswell, and the entire record in this proceeding.

Summary of the Evidence

Public Staff First and Second Partial Stipulations

On March 25, 2020, DEC and the Public Staff entered into and filed the First Partial Stipulation resolving some of the issues in this proceeding between the two parties and delineating those issues for which they had not reached compromise (Unresolved Issues). On July 31, 2020, the Public Staff and the Company entered into and filed the Second Partial Stipulation resolving several additional issues in this proceeding.

The First Partial Stipulation is based on the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through January 31, 2020. The Second Partial Stipulation is based upon the same test period as the Company's Application, adjusted for certain known changes in revenue, expenses, and rate base through January 31, 2020, and May 31, 2020 (May 2020 Updates).

The Second Partial Stipulation outlines the remaining Unresolved Issues as follows: (1) cost recovery of the Company's coal ash costs, recovery amortization period, and return during the amortization period; (2) amortization period for the loss on the sale of the hydro stations; (3) depreciation rates appropriate for use in this case; and (4) any other revenue requirement or nonrevenue requirement issue other than those issues specifically addressed in the Second Partial Stipulation, the First Partial Stipulation, or agreed upon in the testimony of DEC and the Public Staff. Second Partial Stipulation, § II.

Witness De May explained that the First Partial Stipulation resolves several of the revenue requirement issues between the Company and the Public Staff. Tr. vol. 11, 879. Revenue requirement adjustments were agreed upon in the First Partial Stipulation for Storm Costs, aviation expenses, executive compensation and benefits, board of directors, lobbying, sponsorships and donations, rate case expenses, severance, incentive compensation, retired hydro O&M expenses, credit card fees, advertising, weather normalization, growth and usage, and protected federal EDIT. *Id.* These accounting and ratemaking adjustments and the resulting revenue requirement effect of the First Partial Stipulation are shown in Schedule 1 of Boswell Supplemental and Stipulation Exhibit 1, and McManeus Supplemental Rebuttal Exhibit 3, which provide sufficient support for the annual revenue required on the issues agreed to in the First Partial Stipulation. The revenue requirement impact of the issues settled in the First Partial Stipulation is a reduction of the base revenue requirement from that requested in the Application of approximately $78,878,000 to $81,049,000, depending on the resolution of the Unresolved Issues.

The Public Staff's prefiled testimony expressed concerns about certain aspects of the Company's recordkeeping and reporting practices. The stipulating parties resolved these concerns in the Second Partial Stipulation. Section IV.J provides that within 90 days after the Commission issues its final order herein the Company will work with the Public Staff on document retention, project reporting, and other reasonably applicable matters to better assist the Public Staff in future audits of plant. In addition, Section IV.K states that DEC will have its internal Corporate Audit Services conduct an independent review/audit of its materials and supply inventory, and that the terms of the audit should, at a minimum, meet those recommended in the direct testimony of Public Staff witness Metz. Further, Section IV.L of the Second Partial Stipulation provides that DEC and the Public Staff will meet to discuss the Company's plant unitization policies and reach agreement on the Company's reporting obligations.

Witness De May testified that the Second Partial Stipulation resolves most, but not all of the remaining revenue requirement issues between DEC and the Public Staff. Tr. vol. 11, 884. Witness De May provided an overview of the major components of the

Second Partial Stipulation, including an agreement regarding shareholder contributions to the Share the Warmth Program, cost of capital, return of state and federal EDIT to customers, deferral accounting treatment of certain GIP programs, cost-of-service methodology for this case, inclusion of the May 2020 Updates to certain pro forma adjustments subject to the Public Staff's audit of the updates and other terms concerning the May 2020 Updates, the amount of recovery for the Clemson CHP project, and the amortization period for non-ARO environmental costs. *Id.* at 884-87.

In addition, witness De May outlined other areas of agreement, including terms governing the start date of the evidentiary hearings to allow time for the Public Staff to audit the May 2020 Updates, ongoing assessments of the cost effectiveness of GIP-related projects, clarification of GIP costs that are eligible for deferral, commitments to future cost-of-service studies, rate design issues, and commitments to conduct audits and reporting obligations regarding plant and materials and supplies inventory. *Id.* at 887. These accounting and ratemaking adjustments and the resulting revenue requirement effect of the Second Partial Stipulation are shown in Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1, and McManeus Second Settlement Exhibit 2, which provide sufficient support for the annual revenue required on the issues agreed to in the Second Partial Stipulation. The Company's calculation of the revenue requirement impact of the issues settled in the Second Partial Stipulation is an increase in the base revenue requirement of approximately $46,798,000, to be further adjusted by the Public Staff's recommendations in its September 8, 2020 testimony, and pending resolution of the Unresolved Issues. However, the stipulating parties could not determine the total impact to base rate revenues without the Commission's final determination of the Unresolved Issues.

Witness De May testified that he attended public hearings held by the Commission in this matter and personally heard from dozens of customers who are concerned about the impacts of any rate increase on their families and businesses, and he noted that the Company is very mindful of these concerns. *Id.* at 881-82, 887-88. Witness De May stated that the concessions the Company has made in the First and Second Partial Stipulations fairly balance the needs of customers with the Company's need to recover investments made to continue to comply with regulatory requirements and safely provide high quality electric service to its customers, particularly so in the Second Partial Stipulation in light of the current economic conditions of many of the Company's customers due to the COVID-19 pandemic. *Id.* at 882, 888.

Public Staff witness Boswell testified that from the perspective of the Public Staff, the most important benefits provided by the Public Staff Partial Stipulations are: (1) an aggregate reduction in the Company's proposed revenue increase as to specific expense items agreed to by DEC and the Public Staff in this proceeding, and (2) the avoidance of protracted litigation between DEC and the Public Staff before the Commission and possibly the appellate courts. Tr. vol. 17, 276, 286. Based on these ratepayer benefits, as well as the other provisions of the Public Staff Partial Stipulations, the Public Staff believes the Public Staff Partial Stipulations are in the public interest and should be approved. *Id.*

Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEC and the Public Staff have agreed as well as Section III.J. of the Second Partial Stipulation. These accounting adjustments are fully discussed later in this Order.

CIGFUR Stipulation

On May 29, 2020, the Company and CIGFUR entered into and filed the CIGFUR Stipulation. No testimony supporting the settlement was filed.

As part of the CIGFUR Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. CIGFUR Stipulation, § II. Subsequently, on August 6, 2020, the Stipulation was amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the stipulation should be deemed to be fulfilled.

In addition, CIGFUR agreed to support the Company's request for a deferral of GIP costs over three years. CIFGUR Stipulation, § III.A. Because the three-year GIP plan contains estimates, CIGFUR's support for the GIP deferral will be subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases. To the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to otherwise limit the maximum allowed amount of the three-year GIP deferral, CIGFUR supports such cost containment measures.

Section III.B of the CIGFUR Stipulation provides that in the next rate case DEC will propose to allocate the deferred GIP costs among classes consistent with its distribution cost allocation methodologies proposed in this docket, including use of the minimum system methodology (MSM) and voltage-differentiated allocation factors for distribution plant. Additionally, with Commission approval, the Company will use this methodology to allocate GIP costs during the three years for which it may seek recovery in future rate cases.

Under Section IV, the parties agreed to refund unprotected EDIT on a uniform cents per kilowatt-hour (cents/kWh) basis.

Under Section V, DEC and CIGFUR agreed to five conditions related to cost of service and rate design. The first condition would obligate DEC to discuss and consider potential cost-of-service methodologies and to consider the results of a cost-of-service study based on the Summer/Winter Coincident Peak method. The second condition would require DEC in its next rate case to adjust peak demand to remove curtailable/non-firm load, even when the load reduction is not requested. The third condition would require DEC in its next two fuel proceedings to propose the uniform percentage average bill adjustment methodology. The fourth condition would require DEC in its next three rate cases to allocate distribution expenses using the MSM unless the Commission rejects the method. The fifth condition would require the Company to explore certain rate designs and file the rates if there is interest from CIGFUR customers.

Harris Teeter/Commercial Group Stipulations

DEC and Harris Teeter entered into and filed the HT Stipulation on May 28, 2020, and DEC and the Commercial Group entered into and filed the CG Stipulation on June 1, 2020. These settlements are substantially similar, and they resolve several issues between DEC and these two parties, including ROE and capital structure, GIP, and some rate design issues. No testimony supporting either settlement was filed.

As part of the HT and CG Stipulations, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. HT Stipulation, § 4; CG Stipulation, § 4. Subsequently, both stipulations were amended to state that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of each stipulation should be deemed to be fulfilled.

As part of its stipulation with DEC, the Commercial Group neither opposes nor specifically supports the approval of the Company's requested GIP deferral. CG Stipulation, § 1. Harris Teeter supports the approval of the Company's requested GIP deferral with certain conditions detailed therein, including a reservation of Harris Teeter's right to take any position as to the reasonableness of specific GIP costs in a future rate case. HT Stipulation, § 1.

Further, DEC, Commercial Group, and Harris Teeter agreed that any GIP costs allocated to OPT-V customers will be recovered through OPT-V demand charges. They also agreed that the OPT-VSS off-peak energy charge shall be set at 3.0222 cents/kWh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. HT Stipulation, § 3; CG Stipulation, § 3. In addition, the settlements provide that the demand charges for the OPT-VSS rate schedule shall be adjusted by the amount necessary to recover the final OPT-VSS revenue target. *Id.*

Pursuant to Section 5 of the CG Stipulation, Commercial Group agreed that the Company has met with its representatives and adequately addressed its concerns.

NCSEA/NCJC et al. Stipulation

On May 29, 2020, DEC, NCSEA, and NCJC et al. entered into and filed the NCSEA/NCJC et al. Stipulation resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the NCSEA/NCJC et al. Stipulation, the parties initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. NCSEA/NCJC et al. Stipulation, § II. Subsequently, on August 10, 2020, the parties filed an amendment to their stipulation providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the stipulation should be deemed to be fulfilled.

NCSEA and NCJC et al. also agreed to support the Company's request for an accounting order for approval to defer GIP costs for investments in ISOP, Integrated Volt Var Control (IVVC), Self-Optimizing Grid (SOG), Distribution Automation, Transmission System Intelligence, the Distributed Energy Resources (DER) Dispatch Tool, and the 44-kV Line Rebuild. NCSEA and NCJC et al. believe that these investments will directly enable and support the greater utilization of DERs on the Company's system. For all other GIP investments proposed by DEC, NCSEA and NCJC et al. do not oppose the requested deferral accounting treatment. To the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, NCSEA and NCJC et al. support such cost containment measures, subject to a reservation of their rights to review and object to the reasonableness of specific project costs in future rate cases.

Pursuant to other provisions of the NCSEA/NCJC et al. Stipulation, DEC agreed:

(1) to provide, in conjunction with the concurrent commitment of DEP, an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million);

(2) that within six months of the effective date of the stipulation, in addition to the low-income collaborative proposed by DEC, to collaborate with NCSEA and NCJC et al. to design additional low-income EE/DSM program pilots to present to the DEC and DEP EE/DSM Collaborative for consideration; and further, on the condition that the majority of EE/DSM Collaborative participants and DEP and DEC support the program pilots, to file for approval of the program pilots in North Carolina and South Carolina; and

(3) within six months of the effective date of the stipulation, to collaborate with NCSEA and NCJC et al. to design a tariffed on-bill pilot program, which shall include a Pay-As-You-Save or other mutually agreeable alternative program design, for customers in North Carolina, addressing several listed issues; and further, within 18 months of the effective date of the agreement, to either (i) file the pilot for approval with the Commission, provided the parties mutually agree to the terms of the pilot program that is not less than three years in length and, in conjunction with the concurrent commitment of DEP, includes a combined total of no fewer than 700 but no more than 1000 residential customers, or (ii) file a status report with the Commission in this docket.

In addition, DEC agreed to preview a Distributed Generation Guidance Map for North Carolina with the DER Interconnection Technical Standards Review Group (TSRG) in the TSRG meeting during the third quarter of 2020, as well as in the August 2020 ISOP stakeholder meeting, after which DEC will incorporate TSRG and ISOP stakeholder input as appropriate and publish the Distributed Generation Guidance Map for North Carolina.

Further, DEC agreed to include in its 2021 IRP details about how both existing and new DERs and non-wires applications will be examined in its ISOP as means to defer traditional capital investments in the system. DEC also agreed to implement the basic elements of the ISOP process in the 2022 IRP. Following the 2024 IRP, but no later than December 31, 2024, DEC agreed to provide hosting capacity analyses for a representative sample of DEC North Carolina circuits with other provisions and contingencies.

In addition, DEC agreed that it will reasonably include NCSEA and NCJC et al. for input and feedback at material points in its selection process as it identifies the tools and capabilities necessary for ISOP implementation. DEC also agreed to reasonably consider and, where appropriate, incorporate input from the parties with regard to the parameters that ISOP will use to assess issues such as distribution investment needs, the use of existing and future distributed energy resources and non-wires applications, load forecasts, pricing assumptions, and modeling inputs, keeping in mind the overall objective of developing investment plans that meet customer needs and preferences by capturing efficiencies from being a vertically integrated electric utility.

Vote Solar Stipulation

DEC and Vote Solar entered into and filed the Vote Solar Stipulation on June 9, 2020, resolving some of the issues in this proceeding between these parties. No testimony supporting the settlement was filed.

As part of the Vote Solar Stipulation, DEC initially agreed that the revenues to be approved in this proceeding should be adjusted to provide the Company, through sound management, the opportunity to earn an ROE of 9.75% and that this ROE will be applied to the common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt. Vote Solar Stipulation, § II. Subsequently, on August 5, 2020, the parties filed an amendment to the Vote Solar Stipulation, providing that should the Commission approve an ROE of 9.60% applied to a capital structure of 52% equity, 48% debt, this section of the stipulation should be deemed to be fulfilled.

Further, Vote Solar agreed to support the Company’s request for an accounting order for approval to defer GIP costs for investments in ISOP, IVVC, SOG, Distribution Automation, Transmission System Intelligence, the DER Dispatch Tool, and the 44-kV Line Rebuild. Vote Solar believes that these investments will directly enable and support the greater utilization of DERs on the Company’s system. For all other GIP investments proposed by DEC, Vote Solar does not oppose the requested deferral accounting treatment. To the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap or to limit the amount of any GIP investment category specified for deferral treatment, Vote Solar supports such cost containment measures. Further, Vote Solar’s support for the GIP deferral is subject to a reservation of its rights to review and object to the reasonableness of specific project costs in future rate cases.

In addition, DEC committed with Vote Solar to develop potential pilot customer programs prior to the submission of the 2022 IRP to optimize the capability of the GIP investments to support greater utilization of DERs, including customer-sited solar and/or storage facilities (e.g., net metering successor), microgrid systems that benefit and would be paid for by specific benefitted customers, and programmable and load controllable devices or appliances for use in residential and nonresidential demand response programs. If DEC and Vote Solar mutually agree that these programs are cost-effective and meet appropriate Commission requirements, DEC agreed to file such pilot programs for approval by the Commission, and Vote Solar agreed to support such approval by the Commission.

Moreover, DEC agreed that within six months from the effective date of the Commission's order in this docket, DEC will convene a Climate Risk & Resilience Working Group (Working Group) governed by several parameters set out in the stipulation. Within 60 days of the effective date of the Commission's order the Company will make an informational filing in the docket to describe its scoping plan and proposed schedule for the Working Group and will give notice of such filing to all interested parties in all North Carolina and South Carolina dockets and stakeholder processes to which it is a party related to climate or decarbonization policy, the GIP, IRP, and ISOP. DEC further agreed to fund a third-party consultant with experience developing models or analyses for quantifying climate-related impacts on the electric grid to assist stakeholders and the Company with the Working Group, subject to the contingency that DEC will recover the cost of the third-party consultant from ratepayers.

Discussion and Conclusions

As none of the partial stipulations have been adopted by all of the parties to this docket, the Commission's determination of whether to accept or reject each of the stipulations is governed by the standards set out by the North Carolina Supreme Court in *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 500 S.E.2d 693 (1998) (*CUCA I*), and *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 351 N.C. 223, 524 S.E.2d 10 (2000) (*CUCA II*). In *CUCA I*, the Supreme Court held:

> [A] stipulation entered into by less than all of the parties as to any facts or issues in a contested case proceeding under chapter 62 should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding. The Commission must consider the nonunanimous stipulation along with all the evidence presented and any other facts the Commission finds relevant to the fair and just determination of the proceeding. The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes "its own independent conclusion" supported by substantial evidence on the

record that the proposal is just and reasonable to all parties in light of all the evidence presented.

348 N.C. at 466, 500 S.E.2d at 703.

However, as the Court made clear in *CUCA II*, the fact that fewer than all of the parties have adopted a settlement does not permit the Court to subject the Commission's Order adopting the provisions of a nonunanimous stipulation to a "heightened standard" of review. 351 N.C. at 231, 524 S.E.2d at 16. Rather, Commission approval of the provisions of a nonunanimous stipulation "requires only that the Commission ma[k]e an independent determination supported by substantial evidence on the record [and] . . . satisf[y] the requirements of chapter 62 by independently considering and analyzing all the evidence and any other facts relevant to a determination that the proposal is just and reasonable to all parties." *Id.* at 231-32, 524 S.E.2d at 16.

The Commission finds and concludes that the provisions of the First and Second Partial Stipulations, as well as the stipulations with CIGFUR, Harris Teeter, Commercial Group, Vote Solar, NCSEA, and NCJC et al. result from the give-and-take between DEC and the stipulating parties and represent a compromise that is fair and adequate to each stipulating party. Pursuant to *CUCA I* and *II*, these nonunanimous stipulations are some evidence to be considered by the Commission in reaching its decision in this case. The Commission has fully evaluated the provisions of these stipulations and concludes, in the exercise of its independent judgment, that the stipulations should be accepted, in part, and rejected, in part, consistent with the specific discussion and resolution of the various issues discussed below. The parties are free to enter into stipulated provisions that pertain to actions or positions to be taken outside the confines of this proceeding; however, to the extent that DEC committed to certain actions or positions in future proceedings, the Commission concludes that they are not relevant to any issue before the Commission in this case and do not tie the Commission's hands or limit future investigations.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 4

Base Fuel and Fuel-Related Cost Factors

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the Public Staff Second Partial Stipulation, the testimony and exhibits of DEC witnesses McGee and McManeus and Public Staff witnesses Metz and Boswell, and the entire record in this proceeding.

Summary of the Evidence

In her direct testimony Company witness McGee supported the fuel component of the proposed base rates for all customer classes and the fuel pro forma adjustments to the test year operating expenses contained in McManeus Direct Exhibit 1. Tr. vol. 11, 749-50. Witness McGee proposed to use the total prospective fuel and fuel-related costs factors proposed on February 26, 2019, in Docket No. E-7, Sub 1190. *Id.* at 749. Witness

McGee explained that DEC's intent in using the fuel-related costs factors that were proposed at the time the Company's Application was prepared as a component of its proposed new rates was to make it clear that the Company is requesting a rate increase that relates to non-fuel revenues only. *Id.* at 749-50.

In his direct testimony Public Staff witness Metz testified that based on his review of the Company's base fuel factor, the base fuel factor was appropriate and aligned with the Company's proposed and Commission-approved previous annual fuel filing, Docket No. E-7, Sub 1190. Tr. vol. 16, 675.

The Company filed its subsequent fuel factor adjustment case in Sub 1228 on February 25, 2020. Section IV.N of the Second Partial Stipulation provides that should a final Commission order be issued in the fuel rider proceeding prior to the due date for proposed orders in this general rate case proceeding, the total of the approved base fuel and fuel-related costs factors, by customer class, will be the sum of the respective base fuel and fuel-related costs factors set in Sub 1146 and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Sub 1228. Company witness McManeus and Public Staff witness Boswell supported the provision for the total approved base fuel and fuel related costs factors through their testimony in support of the Second Partial Stipulation. Tr. vol. 11, 581-82; tr. vol. 17, 284-86.

The Commission issued a final Order in the Sub 1228 fuel rider proceeding on August 19, 2020. In that order the Commission concluded that effective for service rendered on and after September 1, 2020, DEC shall reduce the base fuel and fuel-related costs in its North Carolina retail rates of 1.7828 cents/kWh, 1.9163 cents/kWh, and 2.0207 cents/kWh for the residential, general service/lighting, and industrial classes, respectively, as approved in Sub 1146, by amounts equal to (0.1801) cents/kWh, (0.1580) cents/kWh, and (0.3555) cents/kWh for the residential, general service/lighting, and industrial classes, respectively. These adjustments result in total base fuel and fuel-related costs of 1.6027 cents/kWh, 1.7583 cents/kWh, and 1.6652 cents/kWh for the residential, general service/lighting, and industrial classes, respectively.

According to witness McGee, the Company will continue to bill customers the fuel rates authorized by the Commission in its 2020 annual fuel proceeding. Tr. vol. 11, 751. As such, there will be no change in customers' bills as a result of including these fuel cost factors in the proposed base rates. *Id.*

Discussion and Conclusions

No intervenor offered any evidence contesting the testimony of Company and Public Staff witnesses in support of the base fuel and fuel-related costs factors therein or the provision in the Second Partial Stipulation for the Company's base fuel and fuel-related costs factors. Further, the Commission gives significant weight to Section IV.N of the Second Partial Stipulation regarding the base fuel and fuel-related costs factors. Accordingly, the Commission finds and concludes for purposes of this proceeding that the total of the approved base fuel and fuel-related costs factors, by customer class — the sum of the respective base fuel and fuel-related costs factors set in Sub 1146 and the annual non-EMF fuel and fuel-related costs riders approved by the Commission in Sub 1228 — are just and reasonable to all parties in light of all the evidence presented.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 5–7

Amortization of Loss on Hydro Station Sale

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of DEC witness McManeus and Public Staff witness Boswell, and the entire record in this proceeding.

Summary of the Evidence

In her direct testimony Company witness McManeus explained that the Company had removed test period operating expenses and rate base amounts related to five hydro stations that were sold on August 16, 2019. Tr. vol. 11, 484. She testified that the Commission approved the sale of the facilities and the transfer of the related certificates of public convenience and necessity in Docket Nos. E-7, Sub 1181, SP-12478, Sub 0, and SP-12479, Sub 0 (Sub 1181). *Id.* In addition, the Commission in those dockets approved the establishment of a regulatory asset for the estimated loss on disposition of the facilities and ordered that the amortization of the regulatory asset begin at the time the sale is closed. *Id.* In an effort to closely align the revenue requirement associated with the loss on the sale to the revenue requirement amount associated with ownership of the facilities, the Company proposed to amortize the estimated loss on the sale over a seven-year period. *Id.* at 485. In her supplemental direct testimony, witness McManeus updated the adjustment, which was based on estimated values, to reflect final accounting entries related to completion of the sale. *Id.* at 508.

Public Staff witness Boswell recommended the deferred loss on the sale of the hydro assets be amortized over 20 years, which would have been the remaining depreciable life of the assets if they had remained in service. Tr. vol. 17, 257. Witness Boswell noted that in its filing for deferral accounting in Sub 1181, the Company asserted that the sale transaction would allow the facilities to continue to serve the customers with clean renewable energy, but at a lower cost. Witness Boswell also noted that the cost-benefit analysis provided by the Company in the Sub 1181, docket was based on the 20-year costs to maintain and operate the facilities and that in the Public Staff's comments and testimony in that docket, the Public Staff had also recommended a 20-year amortization period. *Id.* According to witness Boswell, at the time the Public Staff's comments were filed in Sub 1181, the average remaining life of the facilities was 22.49 years; as of the end of 2019 the remaining depreciable life was 19.95 years. *Id.*

In her rebuttal testimony Witness McManeus stated that she believes the Company's recommended seven-year period is fair because "[t]he revenue requirement resulting from the annual amortization expense using the 7-year amortization period as proposed by the Company closely aligns with the amount of revenue requirement associated with test period annual O&M expense and annual depreciation expense of the hydro units being sold, resulting in minimal change to existing rates." Tr. vol. 11, 523.

Witness McManeus was asked during cross-examination whether customers would experience a decrease in rates in the present proceeding if the loss on the sale of the hydro units was amortized over 20 years as proposed by the Public Staff as opposed to seven years. Witness McManus responded that if something is amortized over seven years the amortization amount is higher than amortizing it over 20 years. Tr. vol. 15, 124. Witness McManeus further testified that the seven-year period was "backed into," taking a bit of guidance from the Commission's order in Sub 1181. *Id*. at 123. In that order, when the Commission approved the deferral of the loss, it also indicated that the amortization amount should be equal to the depreciation expense and thereby provide rate neutrality. *Id*. at 123-24.

On request of counsel for the Public Staff, the Commission took judicial notice of the Commission's June 5, 2019 order in Sub 1181. Tr. vol. 15, 120. In Sub 1181 the Commission noted that it would address the amortization period for the remaining regulatory asset and whether the regulatory asset should earn a return in DEC's next general rate case. No party provided testimony in this proceeding opposing a return.

Discussion and Conclusions

Based on the foregoing and the record, the Commission finds that it is appropriate to accept and adopt the recommendation of the Public Staff. In reaching this conclusion the Commission gives significant weight to Public Staff witness Boswell's testimony and the Commission's June 5, 2019 order issued in Sub 1181. It is undisputed that the purpose of the sale of the hydro units was to enable the Company to supply its customers with electric service based on least-cost principles. The Commission ordered in Sub 1181 that the Company amortize the loss on sale (i.e., the "stranded cost" of the hydro facilities) over the 20-year remaining depreciation period until further order of the Commission. The rationale underlying that decision was the fact that the Company was already recovering costs of the plants in its rates based on the 20-year period. However, in its Sub 1181 order, the Commission held that it would decide the amortization period for the remaining regulatory asset and whether a return on the unamortized balance would be authorized in DEC's next general rate case.

The current case is that next general rate case and presents the Commission with a different situation than in Sub 1181 — an opportunity to change DEC base rates to reflect a fair and reasonable distribution of the net benefits of the hydro sale. The Commission concludes that amortizing the stranded costs over a seven-year period in this case will not reflect a fair and reasonable distribution. Amortizing the stranded costs, recovery of which reduces the net benefits to be enjoyed by customers, over a seven-year period rather than a 20-year period would unreasonably skew the benefits from the sale of the assets toward customers in later years at the expense of customers in earlier years. The Commission finds that the Company has not presented evidence in the present case that amortization over a seven-year period would provide ratepayers with the reasonable benefits of the sale and deferral presented in Sub 1181. The Commission finds and concludes that a 20-year amortization period will result in a more just and fair distribution of benefits over the years that the overall transaction is expected to produce net benefits. The Commission thus concludes that the 20-year amortization period as recommended by the Public Staff should be approved in this proceeding.

Regarding the question of a return, the Commission will allow the Company to earn a return on the unamortized balance as the hydro stations were sold to Northbrook to provide a benefit to customers. Significantly, in its Sub 1181 order, the Commission found that "as part of the Transaction DEC has agreed to purchase all of the energy and RECs generated by the Facilities for five years following the Transaction through renewable power purchase power agreements (RPPAs) with Northbrook. As such, the Facilities will continue to serve customers with clean renewable energy, but at a lower cost over time." Furthermore, no party has opposed the Company's earning a return on the unamortized balance in this proceeding. For these reasons, the Commission finds it is appropriate to allow a return on the unamortized balance of the regulatory asset representing the hydro stations that were sold.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8–13

Depreciation Study

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of DEC witness Spanos and Public Staff witness McCullar, and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Spanos provided a copy of the new deprecation study he prepared for DEC for use in this proceeding as Exhibit 1 to his prefiled direct testimony. Witness Spanos testified as to how he determined the depreciation rates included in the depreciation study. He further testified that he used the same methods and procedures to produce the current depreciation study as he has done in previous DEC depreciation studies. Tr. vol. 12, 140.

Next, witness Spanos discussed the life span estimates for DEC's production facilities. Id. at 139-41. He stated that the life span estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and the estimates for similar facilities for other utilities. For nuclear and hydro facilities that have operating licenses, the life span estimates are based on the license dates for each facility. *Id*. at 140. Witness Spanos further explained that since the last study was conducted, the life spans for several plant facilities for DEC have changed. He stated that Allen Units 4 and 5, Cliffside Unit 5, and Marshall Units 1 and 2 have life spans that are planned to be shorter than currently approved. *Id*. He noted, however, given that the depreciation rates are developed at the location level for Allen and Marshall, the individual life span dates are not presented in the results section of the Depreciation Study. Witness Spanos stated that he believes the revisions for the Allen, Cliffside, and Marshall units to be appropriate.

Witness Spanos additionally testified regarding DEC's replacement of its legacy electric meters. He stated that DEC has a program to replace its existing legacy electric meters with new technology meters. This replacement project is planned to be completed by the end of 2019. In accordance with the Commission's June 22, 2018 order in Sub 1146 (2018 DEC Rate Order), the net book value ($154 million) of the legacy meters will be amortized over 15 years.

Witness Spanos also testified regarding net salvage. Tr. vol. 12, 142-44. He testified that net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net Salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage. Witness Spanos testified that the net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data, information provided by the Company's operating personnel, general knowledge and experience of industry practices, and trends in the industry in general. The statistical net salvage analyses incorporate the Company's actual historical data for the period 2003 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Another topic discussed by witness Spanos was that of dismantlement or decommissioning costs. *Id*. at 144-45. Witness Spanos stated that he included a dismantlement or decommissioning component in the net salvage percentage for steam, hydro, and other production facilities. Witness Spanos explained that the dismantlement component is part of the overall net salvage for each location within the production assets. Based on studies for other utilities and the cost estimates of DEC, it was determined that the dismantlement or decommissioning costs for steam and other production facilities is best calculated by dividing the dismantlement cost by the surviving plant value at final retirement. These amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location. Witness Spanos pointed out that the decommissioning cost estimates are based on the decommissioning studies of each generating site performed by Burns and McDonnell. Witness Spanos noted that these costs tend to increase over time and that for this reason, to allow DEC to recover the full decommissioning costs for each site, he believes these costs need to be escalated to the time of retirement. He included calculations of these escalated costs in the deprecation study.

Public Staff Direct Testimony

Witness McCullar testified that DEC was proposing an increase of $108.5 million in annual depreciation accrual. Tr. vol. 16, 595. She summarized the Public Staff's adjustments to reduce DEC's requested depreciation by $48.5 million, which is an increase of $60 million to depreciation accrual compared to the depreciation rates that were approved in the DEC 2018 Rate Order. She noted that the Public Staff is proposing changes to DEC's requested depreciation rates in the following functional categories: (1) Steam Production Plant (DEC is proposing 4.40% and Public Staff is proposing 3.90%); (2) Hydraulic Production Plant (DEC is proposing 2.00% and the Public Staff is proposing 1.99%); (3) Other Production Plant (DEC is proposing 3.21% and the Public Staff is proposing 3.12%); and (4) Distribution Plant (DEC is proposing 2.28% and the Public Staff is proposing 2.24%). She noted that total depreciable plant as proposed by DEC is 3.12% and 2.99% as recommended by the Public Staff. *Id*. at 596.

Witness McCullar specifically addressed the following additional issues in her testimony.

Contingency

Witness McCullar testified that DEC was again including a 20% contingency for future "unknowns." She proposed to eliminate the 20% contingency for future "unknowns" and noted that in the 2018 DEC Rate Order the Commission ordered that a 10% contingency factor be used. *Id*. at 603-04.

Terminal Net Salvage

Witness McCullar noted that in its 2018 DEC Rate Order the Commission found that DEC's proposal to escalate estimated future terminal net salvage costs to the assumed year of final retirement was reasonable and that the Public Staff was not recommending a change to DEC's proposed escalation of the estimated future net salvage costs in this proceeding. She explained that DEC was inflating the estimated future terminal salvage costs to the year of final retirement and that the future terminal net salvage costs are estimated in DEC's 2016 Decommissioning Study provided in Sub 1146. She further noted that the 2016 Decommissioning Study provides the estimated future terminal net salvage costs in year-2016 dollars. *Id*. at 606. Witness McCullar testified that in the 2018 Depreciation Study, these estimated future terminal net salvage costs are escalated to the year of the assumed retirement of the production plant, and that DEC proposes to collect a portion of these future inflated estimated costs from the current ratepayers in today's more valuable dollars (meaning with inflation the retirement-year dollars will have a lower purchasing power than today's nominal dollar). She further explained that it is these escalated retirement-year dollars that DEC is proposing to include in the calculation of rates to be charged to ratepayers. Witness McCullar stated that the concern is not that retirement-year dollars are worth less than current-year dollars. Rather, determining the cost of removal in retirement-year dollars and then collecting the inflated costs from current customers in more valuable current dollars is unreasonable since it imposes on today's ratepayers too much of the risk associated with a significantly long period of estimated future inflation. *Id*. at 607.

Public Staff witness McCullar testified that inflating the DEC estimated terminal net salvage cost to year 2023 would be a reasonable approach as an escalation year for estimated terminal net salvage costs. *Id*. at 610. Witness McCullar testified that five years is generally consistent with the period of time before the next rate case. The depreciation rates approved in this proceeding are expected to go into effect in 2018 — the year 2023 would be five years later — by which time depreciation rates would have been reviewed in a new base rate case. Therefore, her recommendation in this case is to inflate the terminal net salvage costs to the level of the dollars collected from the ratepayers for the time period the rates set in this proceeding are expected to be effective. This reduces the risk placed on today's ratepayers without exposing the Company to a risk that it will not be able to collect its actual net salvage costs over the long-term.

Interim Net Salvage

Witness McCullar testified that in the 2018 DEC Rate Order the Commission found that the interim net salvage percentages could be re-examined for accounts 342, 343, 344, 345, and 346 in a future rate case proceeding. *Id*. at 612-13. Witness McCullar testified that for interim net salvage costs, DEC is proposing a -5% interim net salvage percentage. Witness McCullar testified that for the last 3 years DEC has shown a positive net salvage, meaning that DEC has booked gross salvage amounts that have more than covered the incurred cost of removal costs. Therefore, witness McCullar proposed a 0% interim net salvage amount because DEC has not incurred interim net removal costs. *Id*. at 614. She noted, however, that 0% interim net salvage includes only the net salvage costs of retirements that occur prior to the final decommissioning of the plants — not the final decommissioning costs.

Mass Property Future Net Salvage

Witness McCullar testified that she had reviewed the reasonableness of DEC's proposed future net salvage for a mass property account and she was recommending -10% for Account 366, Underground Conduit, which is different than DEC's proposed -15% for this account. Witness McCullar noted that salvage ratios are a function of inflation and that the calculation of the historic net salvage ratio includes the impact of high historic inflation rates since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. *Id*. at 617. In other words, due to inflation the amounts in the numerator and denominator of the net salvage ratio are at different price levels. Witness McCullar testified that her proposed future net salvage accrual amounts consider DEC's historic practices and the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements based on the type of investments in the account and her previous experience. *Id*. at 624.

DEC Rebuttal Testimony

Witness Spanos testified that witness McCullar's recommendations for net salvage are not established in a manner that will allow DEC to fully recover its future net salvage amounts. Tr. vol 22, 178. Witness Spanos testified that net salvage is estimated as the cost to retire an asset, net of any gross salvage, at the time the asset is expected to be retired. Net salvage is not estimated as today's cost to retire an asset. He stated that the reason for this is that if today's costs were estimated, then the application of straight-line depreciation would typically fail to recover the full cost to retire the asset because costs tend to increase over time. Witness Spano noted that the Commission ruled on this issue in the 2018 DEC Rate Order and found that full future net salvage costs should be included in rates and that estimating net salvage as the future costs to retire an asset is consistent with authoritative texts and depreciation practices. Witness Spanos further testified that witness McCullar's actual proposed depreciation rates incorporate the escalation concept consistent with the Commission's 2018 DEC Rate Order and that she makes one proposal for net salvage for distribution plant that is not consistent with that order. *Id*. at 181. Witness Spanos stated that witness McCullar proposed a less negative net salvage estimate for Account 366, Underground Conduit. He stated that while overall her proposal for this account does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her proposal other than to compare her results to the Company's recently recorded costs. Additionally, he noted that witness McCullar supported her proposal by arguing against including future inflation in net salvage estimates. Witness Spanos further testified that witness McCullar provided four cases where other state commissions removed the escalation of estimated future terminal net salvage costs. Witness Spanos refuted this by noting that one of these cases was a settlement, two are more than a decade old, and since those cases a number of power plants have been retired or decommissioned, many before they were fully depreciated and without full recovery of terminal net salvage. *Id*. at 185. Witness Spanos further refuted the testimony of witness McCullar by quoting the Commission's 2018 DEC Rate Order:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.

Id. at 186 (quoting 2018 DEC Rate Order at 175). Witness Spanos testified that witness McCullar only cites to a handful of cases to support her claim and that the vast majority of jurisdictions use the Company's approach to net salvage.

DEC witness Spanos also discussed coal ash closure costs. Witness Spanos testified that net salvage costs were included in the depreciation studies he performed for DEC as of 2003, 2007, and 2011 for most production plant accounts. *Id*. at 206. He stated that the issue is not that the Company has not included net salvage in its depreciation rates, but rather that the information DEC has today shows that the costs will be higher than anticipated. He stated that in addition to the background discussed above, the higher costs are function of the challenge in estimating future costs, which the Commission has recognized in noting that even though DEP included coal ash costs in its decommissioning studies, these estimates were too low compared to actual costs. Witness Spanos additionally stated that the prior DEC depreciation studies included terminal net salvage. *Id*. However, the terminal net salvage costs were not based on a decommissioning study as was the case in the last two depreciation studies (i.e., Sub 1146 and the instant case). *Id*. Due to factors such as the uncertainty of decommissioning costs, the tasks involved in decommissioning, and the timing of these costs the Company did not have similar decommissioning studies performed for the 2011 depreciation study and earlier studies. Instead, the estimates in those studies were based on the analysis of historical net salvage and retirements for production plant accounts. Because these estimates were implied to the entire account (rather than just the portion to be retired as interim retirements), they implicitly included a terminal net salvage component. Thus, although the specific cost elements were not defined, DEC has been recovering terminal net salvage costs since at least 2003. Witness Spanos noted that in Sub 1146 the specific decommissioning costs were more certain and therefore could be included at a greater level of detail.

Witness Spanos additionally testified that in the deprecation study he recommended an interim net salvage percentage of -6% for other production accounts, except for rotable parts at combined cycle plants. Witness Spanos noted that in the Commission's 2018 DEC Rate Order the Commission adopted an estimate of 0% for these accounts. He stated that since that time the data has changed and indicates a negative net salvage estimate. *Id*. at 194.

Discussion

Contingency Factor

Public Staff witness McCullar recommended that the currently approved 10% contingency for future "unknowns" included in DEC's estimate of future terminal net salvage costs continue to be used as opposed to the 20% proposed by the Company. Tr. vol. 16, 603. Witness McCullar noted that in the 2018 DEC Rate Order the Commission approved the use of a 10% contingency factor instead of the 20% contingency factor requested by DEC and included in the DEC Decommissioning Cost Estimate Study filed as Doss Exhibit 4 in that docket. She noted that in 2018 DEC Rate Order the Commission stated:

> The Commission is confident that a 10% contingency factor, while less than DEC's requested factor of 20%, should protect the Company from additional costs it will incur but cannot specify at the present date. The Commission also finds that a 10% contingency factor properly reflects the inclusion of items that should push unknown costs downward (i.e., increase in scrap prices, etc.) thereby protecting the ratepayers as well. Based on the foregoing, the Commission concludes that including a contingency factor of 10% should be utilized by the Company.

Id. at 603 (quoting 2018 DEC Rate Order at 172-73). Witness McCullar noted that DEC's proposed future terminal net salvage costs are again supported by the same DEC Decommissioning Cost Estimate Study reviewed in the 2018 DEC Rate Order.

DEC witness Spanos disagreed with witness McCullar's proposal to continue to use the 10% contingency previously approved by the Commission, stating that DEC has learned over the two years since the last Decommissioning Study was performed that the contingency estimates were understated. Tr. vol. 22, 259. He did not, however, provide any specific breakdown of costs to support the statement, other than to indicate that it was supported by experience from other industry participants and because more facilities have been decommissioned in recent years. *Id.*

The Commission agrees with DEC that inclusion of a contingency is often a standard industry practice to cover potential unknown costs that may or may not occur. However, the Commission agrees with the Public Staff that DEC has presented no new information or data supporting the need for a contingency percentage greater than the 10% contingency most recently approved by the Commission in the 2018 DEC Rate Order. As quoted above, in that proceeding the Commission expressed some concern regarding the accuracy of the decommissioning study, finding that DEC failed to consider certain factors, but concluded that a 10% contingency was fair to all parties.

The Commission acknowledges witness Spanos's experience and expertise, yet it notes that the contingency percentage utilized in the Depreciation Study and recommended in his testimony is based on the same Decommissioning Study used in the 2018 DEC Rate Order. In addition, witness Spanos does not provide any new data or information to support his claims regarding recent industry experience supporting an increased contingency percentage. This unsupported position would inappropriately shift a greater portion of the risk of future unknown, unidentified costs on current ratepayers.

The Commission finds that the increased contingency proposed by DEC in this proceeding is not supported by substantial evidence and therefore concludes that it is reasonable and appropriate for DEC to continue to use a contingency factor of 10% for net terminal salvage.

Other Production Interim Net Salvage

DEC witness Spanos testified that he recommended an interim net salvage percent of -6% for Other Production accounts, except for rotable parts at combined cycle plants. Tr. vol. 22, 193. He recognized that the Commission adopted an estimate of 0% for these accounts in Sub 1146 but stated that data over the past two years supports a negative net salvage estimate for each of these accounts. *Id.* Witness Spanos contended that the higher gross salvage numbers in DEC's previous depreciation study were related to the rotable parts of combined cycle facilities that are regularly refurbished and typically experience positive net salvage. *Id.* at 195. He noted that since the previous study, DEC has begun to account for rotable parts in a separate sub-account, resulting in the non-rotable parts accounts experiencing negative net salvage. *Id.* at 196.

Public Staff witness McCullar recommended an adjustment to the interim net salvage percentages of -5% proposed by DEC for Other Production Accounts 342, 343, 344, 345, and 346. Tr. vol. 16, 613. Witness McCullar pointed out that the historical analyses for these accounts show that, on average, the net salvage has been a positive $6,404,164 per year for the last three years and a positive $7,593,793 per year for the last five years. She explained that these positive net salvage amounts indicated that DEC's booked gross salvage exceeded the Company's incurred costs of removal and thus, DEC did not need to collect interim removal costs for these accounts. Therefore, witness McCullar proposed the continued use of a 0% interim net salvage, consistent with the Commission's finding in Sub 1146 and based on DEC's actual experience since that time. She noted that the 0% interim net salvage would not include the final decommissioning costs. *Id.*

Public Staff witness McCullar testified that in addition to relying on historic net salvage ratios, which are influenced by historic inflation levels, she also reviewed future net salvage costs included in DEC's proposed depreciation accrual and the actual net salvage costs incurred by DEC on average over the recent five-year period. Tr. vol. 16, 22. Witness McCullar noted cases in several jurisdictions that have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future percentages that recognized the time value of cost of removal due to inflation. *Id.* at 619-21. Table 3 included in Witness McCullar's testimony provided a comparison of the actual net salvage costs incurred by DEC on average over the recent five-year period to future net salvage costs included in DEC's and the Public Staff's proposed depreciation accruals. Witness McCullar testified that her analysis provides a "reasonableness check" of the proposed future net salvage percentages, and that her "proposed future net salvage accrual amounts consider DEC's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience." *Id.* at 624. As a result of her analysis, for Account 366, Underground Conduit, Witness McCullar recommended a future net salvage percent of -10%, which differs from DEC's proposed -15%. *Id.* at 615. Witness McCullar noted that even under her recommendation, the annual accrual for Account 366, Underground Conduit net salvage would still be $231,716, which is about 14.3 times the average annual amount DEC actually incurred. She further testified that her recommendation provides recovery of the expected cost of removal in the near future and builds the reserve for the future cost of removal associated with future retirements. *Id.* at 625.

DEC witness Spanos in rebuttal stated that the existence of a small number of instances where different approaches were used does not indicate that DEC's approach is consistent with the method used in the vast majority of jurisdictions. Tr. vol. 22, 184. He also testified that he did not believe that witness McCullar's analysis provides a reasonable basis to estimate future net salvage because it is based on the premise that depreciation accruals for net salvage should be similar to, if not the same as, the net salvage occurred each year. He stated that the goal of depreciation is to recover capital costs, including net salvage, over the service life of the assets and that there is not necessarily alignment between depreciation accruals for net salvage and incurred net salvage. Lastly, he noted that expressing historical net salvage as a percentage of historical retirements as he proposes properly recognizes the relationship between net salvage and retirements. *Id.* at 191-92.

On cross-examination, DEC witness Spanos testified that because the net salvage percent should reflect what is expected to happen going forward, sole focus on historical analysis is not sufficient. *Id.* at 262. He noted that with regard to Account 366, however, based on informed judgment, relying on historic salvage over a longer period of time is more representative than the most recent five-year period of time. *Id.* at 264. Witness Spanos acknowledged that the Kansas State Corporation Commission (KSCC) in a recent decision found that a net salvage analysis that estimates appropriate levels of future net salvage and does not rely solely on historic expense levels is appropriate. *Id.* at 265-67 (citing Order on Atmos Energy Corporation's Application for a Rate Increase; No. 19-ATMG-525-RTS, at ¶¶ 52-54 (K.S.C.C. Feb. 24, 2020). He also acknowledged that the KSCC found that the approach recommended by the KSCC Staff in that proceeding, which in part considered the level of net salvage in recent years, not as a percentage of retirements, best balanced the interests of the utility's current and future ratepayers. *Id.*

Based on the above evidence, the Commission finds that the Public Staff's proposal of a future net salvage percent of -10% for Account 366, Underground Conduit, is reasonable since it is within the range of the historic net salvage percentage, Spanos Ex. 1 at 342, and builds a reserve for future removal costs, tr. vol. 16, 623-24, while balancing the interests of current versus future ratepayers.

Terminal Net Salvage

Establishing the service value of the Company's assets requires determining the net salvage costs of those assets that will be incurred in the future. As DEC witness Spanos explained, using the straight-line method of depreciation, these costs are recovered ratably, or in equal amounts, each year over the life of the Company's plant. Tr. vol. 12, 146. This approach is consistent with the USOA, which specifies that the cost of removal is the actual amount paid at the time the transaction takes place. Tr. vol. 22, 187. As such, including the future cost of net salvage for plant accounts is consistent with established depreciation concepts. *See* 2018 DEC Rate Order at 173. In developing decommissioning cost estimates it is necessary to escalate the estimates to the time period in which the cost is expected to be incurred. *Id.* at 173.

Witness McCullar testified that net salvage estimates for decommissioning the Company's power plants are escalated to the date of final retirement, consistent with the 2018 DEC Rate Order. Tr. vol. 16, 605. Confusingly, however, witness McCullar proceeded to discuss the concept of escalation and appeared to advocate instead for only escalating costs to the year 2023. Witness McCullar testified that she selected 2023 because it "would inflate the terminal net salvage costs to the level of the dollars collected from the ratepayers for the time period the rates set in this proceeding are expected to be reasonable." *Id.* at 610. Witness McCullar contended that it would be unreasonable to collect inflated costs of removal in current dollars because it imposes too much risk on ratepayers due to the significant period of time over which the inflation is estimated. *Id.* at 607. Additionally, Witness McCullar noted that four other jurisdictions have removed the escalation of estimated future terminal net salvage costs. *Id.* at 611-12.

As explained by witness Spanos, the Commission reviewed this concept in Sub 1146 and determined that "the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the DEC Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted." Tr. vol. 22, 180 (quoting 2018 DEC Rate Order at 175). The Commission also concluded that estimating net salvage as the future cost to retire an asset is consistent with sound depreciation practices and authoritative texts. *Id*. (quoting 2018 DEC Rate Order at 174). Specifically, the Commission cited the National Association of Regulatory Utility Commissioners (NARUC) Public Utility Depreciation Practices for the principle that "[n]et salvage is the difference between gross salvage that will be realized when the asset is disposed of and the costs of retiring it." *Id*. (quoting 2018 DEC Rate Order at 174). The Commission also cited Wolf and Fitch, another highly regarded authoritative depreciation text, for the position that inflation is appropriately a part of the future cost of net salvage. *Id*. at 189-90 (quoting 2018 DEC Rate Order at 174). In his testimony, Witness Spanos provided the following passage from Wolf and Fitch:

> The matching principle specifies that all cost incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring an asset currently in service must be accrued and allocated as part of the current expenses.

Id. at 189. Wolf and Fitch also make clear that inflation is part of the future cost of net salvage. Witness Spanos pointed out that Wolf and Fitch state the following:

> Negative salvage is a common occurrence. With inflation, the cost of retiring long-lived property, such as a water main, may exceed the original installed cost.

Id. Additionally, with respect to intergenerational equity, Witness Spanos noted that Wolf and Fitch state:

> The accounting treatment of these future costs is clear. They are part of the current cost of using the asset and must be matched against revenue. While the current consumers would say they should not pay for future costs, it would be unfair to the future users if these costs were postponed.

Id. at 189-90. Finally, Wolf and Fitch also argue against a present value or current value concept. Witness Spanos provided the following excerpt from Wolf and Fitch:

> Some say that although the current consumers should pay for the future costs, the future value of the payments, calculated at some reasonable interest rate, should equal the retirement cost. Studies show that the salvage is often "more negative" than forecasters had predicted.

Id. at 190.

Accordingly, witness Spanos contended that Commission precedent, authoritative texts, and sound depreciation practices all support escalating terminal net salvage costs to the date the costs are expected to be incurred rather than some artificially foreshortened date and that while witness McCullar claimed that four other jurisdictions removed the escalation of estimated future terminal net salvage costs, none of the cases witness McCullar cited change the fact that the Commission has already decided this issue in Sub 1146. *Id.* at 185. Further, witness Spanos explained that of the four cases witness McCullar cited, one is a settlement agreement and two are from more than a decade ago. *Id.* at 185. Since that time, a number of power plants have been retired and decommissioned — many prior to being fully depreciated and without full recovery of terminal net salvage. Accordingly, the cases witness McCullar cites are not particularly relevant to the instant proceeding. Moreover, in Sub 1146 the Commission found that the Company's approach to net salvage is used by the vast majority of regulatory jurisdictions. *Id.* at 185 (quoting 2018 DEC Rate Order at 175). Specifically, the Commission stated:

> The fact is the vast majority of jurisdictions use a method for net salvage in which future net salvage is estimated at its future cost and recovered through straight-line depreciation (also known as the traditional method). Approximately 46 out of 50 jurisdictions recover future costs using the straight-line depreciation method.

Id. at 186 (quoting 2018 DEC Rate Order at 175).

North Carolina is one of those majority jurisdictions that uses the traditional method. The cases cited by witness McCullar are in the minority and for that reason should not be afforded any weight in this proceeding. *Id*. at 186. Finally, the Commission previously found witness McCullar's approach to estimating terminal net salvage to be deficient. *Id.* at 182. In the 2018 DEC Rate Order, witness McCullar challenged the inclusion of the full future net salvage cost in depreciation and instead proposed to include only estimates of net salvage costs at current cost levels. *Id.* at 180. As witness Spanos explained above, the Commission already reviewed this concept in Sub 1146 and did not find witness McCullar's arguments persuasive. *Id.* at 181. In the 2018 DEC Rate Order, the Commission stated the following:

> Witness McCullar's approach is not supported by sound depreciation methods and would likely result in the under recovery of net salvage costs over the life of the asset. To that end, other state utility commissions have rejected witness McCullar's alternative approach as unsupported. For example, in a recent case before the Washington Utilities and Transportation Commission (WTC), witness McCullar advanced similar arguments against the escalation of terminal net salvage costs along with other recommendation related to depreciation. In rejecting the recommendation, the WTC noted that Public Counsel and witness McCullar provided no response to the critique that witness McCullar's approaches were not supported by authoritative accounting literature. The WTC found witness McCullar's net salvage proposal "[v]ague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions."

Id. at 182 (quoting 2018 DEC Rate Order at 175).

Considering all the evidence, the Commission finds and concludes that the escalation of terminal net salvage cost and the use of the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study is just and reasonable, appropriate for use in this case, and is adopted.

Mass Property Future Net Salvage

Net salvage estimates are expressed as a percentage of the original cost retired. *Id*. The method for determining the estimated net salvage percent depends on the type of property. *Id.* at 183. For power plants, the estimate is typically based on a decommissioning study, with additional net salvage incorporated for interim retirements. For mass property accounts such as those for transmission and distribution plant, net salvage estimates are based in part on statistical analyses of historical net salvage data. *Id.* In this case, the statistical net salvage analyses incorporate the Company's actual historical data from 2003 through 2018 and considers the cost of removal and gross salvage ratios to the associated retirements during the 16-year period. *Id*. at 143.

Witness Spanos in his Depreciation Study recommends a net salvage percentage of -15% for Account 366, Underground Conduit. Witness McCullar recommends a future net salvage percent of -10% for Account 366, Underground Conduit. Tr. vol. 16, 615. Witness McCullar expressed concern with the Company's historic net salvage ratios calculated in the Depreciation Study. Specifically, witness McCullar took issue with using a net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator. Witness McCullar explained that due to inflation, the amounts in the numerator and denominator of the net salvage ratio are at different price levels. *Id.* at 617-18. Witness McCullar noted that five other jurisdictions have adopted future net salvage percentages that recognized the inflated dollars included in the historic net salvage ratio and adopted future net salvage percentages that recognize the time value of cost of removal due to inflation. *Id.* at 618-21.

In response, witness Spanos testified that witness McCullar's proposal is not consistent with the Commission's decision in Sub 1146 and is unsupported by the record. Tr. vol. 22, 181-82. Witness McCullar supports her treatment of Account 366 by arguing against including future inflation in net salvage estimates. As witness Spanos previously testified, the Commission has already decided against witness McCullar's position on this concept and found that the Company's approach was widely supported. Overall, while witness McCullar's proposal for Account 366 does not have as significant an impact as her proposals for other accounts, she does not provide any statistical basis for her proposal. *Id.* The only analytical method witness McCullar provides in support of her proposal is a comparison of the net salvage costs included in the proposed depreciation rates to the amount of net salvage DEC has incurred, on average, over the past five years. This type of analysis performed by witness McCullar does not provide a reasonable basis to estimate net salvage. Additionally, NARUC and Wolf and Fitch do not support witness McCullar's approach for mass property accounts. *Id.* at 191-92. In fact, the Company is unaware of any authoritative texts that support witness McCullar's analysis. *Id.* Witness Spanos also notes that witness McCullar adopted this backward looking "recent history" approach for calculating net salvage only with regard to Account 366 and not to other property accounts. Tr. vol. 23, 70. At the hearing in this matter, witness Spanos testified extensively that relying solely on recent historical data, as witness McCullar does for her mass property Account 366 recommendation, is inappropriate. Tr. vol. 22, 261-63. He testified to the following:

> So in each category depending on the assets and on what you learned from the Company and doing studies within the industry, you're able to come up with the most appropriate net salvage percentage that would incorporate not only the overall but also the most recent as well as what's expected in the future. Because the net salvage percent that you determine is what we expect to happen going forward, so we can't just focus on the past.

Id. at 262.

In this regard, witness Spanos also testified that conduit is not typically an asset that is removed upon retirement and that this further supports a more negative net salvage value as proposed by the Company. *Id.* at 264. Witness Spanos was also asked on cross-examination about the net salvage calculation in an Atmos Energy rate proceeding in Kansas in which witness McCullar testified. Public Staff Spanos Cross-Examination Ex. 1. This testimony did not undermine witness Spanos' position on net salvage, however, because it was clear from the face of the order in that proceeding that the KSCC explicitly rejected a proposed negative salvage calculation based on a "recent history" approach similar to that offered by witness McCullar in this case. *Id.* at ¶ 54.

Considering all of the evidence, the Commission finds and concludes that the Company's proposed future net salvage for mass property Account 366, Underground Conduit, is just and reasonable, appropriate for use in this case, and is adopted.

Fifteen-Year Service Life for AMI Meters

DEC requested a 15-year depreciation life for AMI meters in this proceeding. As explained by witness Spanos, a 15-S2.5 survivor curve was recommended by DEC for AMI meters. Tr. vol. 22, 197. Spanos testified that DEC's position is consistent with the manufacturer's recommendation for the physical life of the AMI meters and accounted for alternative reasons for retirement such as damage or obsolescence. *Id.*

Public Staff witness McCullar recommended a 17-year service life for AMI meters. Witness McCullar testified that a 17-year life is in the middle of the manufacturer's range, is a reasonable estimate based on the manufacturer's expected life of the AMI meters, and is fair to the Company and the ratepayer. Tr. vol. 16, 615.

In response witness Spanos pointed out that the Commission approved the 15-year service life for AMI meters in the 2018 DEC Rate Order. DEC used a 15-year average service life in its previous depreciation study in Sub 1146. The 2018 DEC Rate Order adopted the depreciation rates proposed by DEC, except for certain depreciation rates discussed in the decision. As witness Spanos explained, because the 15-year average service life was not specifically identified and modified in the 2018 DEC Rate

Order, the 15-year average service life was adopted by the Commission. Tr. vol. 22, 196-97. Moreover, DEC's cost-benefit analysis for AMI meters was based on a 15-year average service life and the Commission had specifically requested that such analysis include the "cost of replacing AMI meters at the end of their 15-year useful life." *Id*. at 197 (quoting 2018 DEC Rate Order at 117).

On cross-examination by Public Staff counsel, witness Spanos further bolstered the reasonableness of a 15-year average service life for AMI meters by indicating that this period is the most common service life used for this type of asset in the industry and based on the type of asset, this survivor curve most appropriately reflects the manufacturer's expectations. Tr. vol. 12, 174.

Witness McCullar provided no new evidence in the instant case that supports changing the 15-year average service life approved by the Commission. Witness Spanos noted that witness McCullar's arguments are almost identical to those she presented in Sub 1146, which were not persuasive to the Commission. Tr. vol. 22, 197-98. Additionally, witness McCullar simply took the mid-range of the manufacturer's life without considering issues like technological obsolescence. In that regard, witness McCullar made no attempt to distinguish the type of asset, which is a critical consideration when there is limited historical experience.

Based upon all the evidence, the Commission finds and concludes that the Company's request to establish a 15-year average service life for AMI meters is just and reasonable and appropriate for use in this case.

Conclusions

Based on the foregoing conclusions regarding the Depreciation Study filed by DEC in this proceeding as Spanos Direct Exhibit 1, the Commission finds that DEC shall: (1) continue to use a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs; (2) use an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346, (3) use the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study; (4) use its proposed future net salvage for mass property Account 366, Underground Conduit; and (5) use an average service life of 15 years for new AMI meters being deployed. The Commission further concludes that except where specifically addressed in this Order, the remaining depreciation rates as proposed by DEC in this case shall be used in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 14–15

Early Retirement of Coal Plants

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of DEC witnesses De May, Spanos, and McManeus and Public Staff witnesses Metz and Boswell, and the entire record in this proceeding.

Summary of the Evidence

Within the context of its new Depreciation Study, DEC altered the life spans of Allen Units 4 and 5 and Cliffside Unit 5 to be shorter than what is currently approved. DEC witness De May explained that "[a]s part of our strategy to reduce our reliance on coal, we have taken a fresh look at the viability of several of our coal-fired plants and have concluded that making shifts in the expected remaining depreciable lives of some of our coal-fired assets is a reasonable action to take now, while we continue to monitor the changing industry landscape and impacts of markets forces." Tr. vol. 11, 859.

DEC witness Spanos testified that DEC intends to retire Allen Units 4 and 5 in 2024 and Cliffside Unit 5 in 2026. Tr. vol. 22, 198. He testified that the new life span for Allen Units 4 and 5 is 67 years and the new life span for Cliffside Unit 5 is 54 years. Tr. vol. 12, 141. Witness Spanos incorporated these shortened life spans into the Depreciation Study and recommended depreciation rates using these retirement dates. Tr. vol. 22, 198. DEC witness Spanos stated that the revised life spans are reasonable because in recent years original life spans for steam production facilities have been shortened due to unit efficiencies and environmental regulations. Tr. vol. 12, 141.

Public Staff witness Metz testified that these retirement dates are earlier than shown in DEC's 2018 IRP and 2019 Update filed on September 3, 2019, in Docket No. E-100, Sub 157. Witness Metz further testified he believes that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. Tr. vol. 16, 671-73.

Public Staff witness Boswell noted the planned retirement dates of Allen Units 4 and 5 and Cliffside Unit 5, and she recommended a five-year depreciation rate for the plants. Witness Boswell, however, testified that she recommended that Public Staff witness McCullar restore the depreciation rate of these units to the depreciation rates approved in the Company's last general rate case in Sub 1146. Tr. vol. 17, 245. Witness Boswell testified that her recommendations regarding the depreciation change were based on the following reasons: (1) although the Company has stated in its testimony that it intends to retire these plants, it has not presently done so; (2) the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant, and, at the date of actual physical retirement, any remaining net book value be placed in a regulatory asset account and amortized over an appropriate period, to be determined in a future general rate case; and (3) the Public Staff believes it is appropriate to continue this consistent treatment of retired plants. *Id.*

Company witness McManeus testified in her rebuttal testimony that the Company disagrees with the Public Staff's adjustment. Company witness Spanos testified that as a matter of principle, the concept witness Boswell sets forth does not comport with the USOA or with generally accepted depreciation principles. Witness Spanos further stated that while the Public Staff may have taken this position in the past, it is inequitable by definition because the costs that would be placed in a regulatory asset account and amortized over a given period will be recovered after the facility is retired. He further stated that the Public Staff's proposal will, by design, result in intergenerational inequity. Tr. vol. 22, 200-01.

During cross-examination, witness Spanos accepted that under N.C.G.S. § 62-35 the Commission sets the rules for DEC's North Carolina retail accounting practices. Witness Spanos further agreed that Commission Rule R8-27 provides for the FERC USOA to be the default system of accounts for electric utilities that are regulated by the Commission. Tr. vol. 22, 282-83. Finally, witness Spanos testified that the Commission has historically provided for costs to be recovered from customers after assets have been retired. During cross-examination, witness Spanos was presented with two examples in which the depreciation expense of DEP's plants were recovered from ratepayers in the years after they were retired. Tr. vol. 22, 287-92; Public Staff Doss Spanos Rebuttal Cross-Examination Ex. 2.

Discussion and Conclusions

Based on the foregoing and the record, the Commission finds that it is appropriate to require DEC to continue to depreciate the Allen Units 4 and 5 and Cliffside Unit 5 generating plants based upon their remaining useful lives as approved in Sub 1146. In reaching this conclusion the Commission gives significant weight to Public Staff witnesses Boswell's and Metz's testimonies. The Commission agrees with witness Metz that the Company's IRP proceeding is the appropriate venue for a thorough review of early, or any, generation retirements. Moreover, the Company did not file the requested accelerated depreciation for the plants in either its 2018 IRP or the 2019 Update, the latter of which was filed one month prior to DEC's filing of the present rate case.

Witness Boswell testified that the Public Staff has consistently recommended leaving the depreciation rates set at the original retirement date of the plant. Further, she stated that at the date of actual physical retirement any remaining net book value should be placed in a regulatory asset account and amortized over an appropriate period to be determined in a future general rate case. The Commission determines that this methodology is supported by the examples that the Public Staff provided during cross-examination of Company witness Spanos. When presented with Public Staff Doss Spanos Rebuttal Cross-Examination Exhibit 2, witness Spanos affirmed that DEP used the same methodology as proposed by witness Boswell in this proceeding in its last rate case, Docket No. E-2, Sub 1142 (Sub 1142). Witness Spanos further confirmed this same treatment was approved by the Commission in Docket No. E-2, Sub 1023 for retirement of DEP's Cape Fear, Lee, Robinson, Weatherspoon, and Morehead City coal plants.

The Commission has strived consistently to balance allowing utilities the full recovery of early generating plant retirement costs while not unduly burdening ratepayers. In the present case the Company's proposed accelerated depreciation would unduly burden the ratepayers for the next several years as they would be paying more for electric service. On the other hand, DEC would be recovering the plants' costs more quickly than last supported by its IRP, which is where generation mix and service lives of DEC's assets are fully vetted. As DEC has not updated its IRP for the service life changes of the Allen Units 4 and 5 and Cliffside Unit 5 generating plants, the Commission and other parties have not had the chance to fully examine the issue within the context of an IRP. For these reasons, the Commission finds using the Company's approach at this time would yield an unbalanced disproportionate result.

Therefore, in light of the foregoing, the Commission finds that the depreciation for the Allen Units 4 and 5 and Cliffside Unit 5 generating plants should be based upon their remaining lives as presented in Sub 1146, and upon the actual retirement of each unit, the remaining net book value should be placed in a regulatory asset account to be amortized over an appropriate period which will be determined in a future rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 16–18

Alleged Uneconomical Coal Plant Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the testimony and exhibits of DEC witness Immel, Public Staff witness Metz, NC WARN witness Powers, Sierra Club witness Wilson, and Tech Customers witness Strunk; and the entire record in this proceeding.

Summary of the Evidence

DEC Application and Direct Testimony

In its Application, DEC stated that since its previous rate case it has made capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units, and to allow certain coal units to burn natural gas. The Company stated that by enabling natural gas co-firing (dual fuel optionality or DFO), it can increase fuel flexibility and further reduce carbon emissions across the Carolinas to benefit customers. Application at 4-5, 7.

Company witness Immel described the Company's Fossil/Hydro/Solar Operations (FHO) fleet and provided operational performance results for those assets during the test period. Tr. vol. 12, 53-54, 59-61. Witness Immel also addressed major FHO capital additions DEC has completed since the previous rate case. Witness Immel explained that the Company has made significant investments in the coal fleet to meet environmental regulations to allow for the continued operation of active plants. Witness Immel also discussed the DFO conversion projects at Cliffside Station and Belews Creek Unit 1, which he stated allow the Company to utilize the most cost-effective fuel and provide fuel flexibility. Witness Immel testified that the Company prudently incurred all of these costs. Furthermore, he stated that these investments are used and useful in providing electric service and benefit customers as they have enabled DEC to continue to provide safe, efficient, and reliable service at least reasonable cost and have reduced DEC's environmental footprint by adding state-of-the-art technology for reducing emissions and expanding the use of natural gas generation at a time when the natural gas market is providing low prices. *Id.* at 56-59.

Public Staff Direct Testimony

In his direct testimony Public Staff witness Metz discussed his review of DEC's capital additions to the FHO fleet. Witness Metz noted that his investigation included, in addition to reviewing the Company's testimony, an audit of specific expenditures, initial and follow-up discovery, teleconferences between and interviews with the Company and Public Staff, site visits, and review of the overall projects with Company management. Tr. vol. 16, 660-61. Witness Metz recommended an adjustment to remove the capital project costs related to the DFO conversion project at Belews Creek. Upon further review, witness Metz reversed that recommendation in his supplemental testimony. Based on the Company's prudence in capital investments in its FHO generation assets he recommended no disallowance. *Id.* at 661-64,680.

NC WARN Direct Testimony

NC WARN witness Powers recommended disallowance of the Company's costs for the DFO conversion projects. Witness Powers contended that the investments in these projects were not reasonable or prudent based on his assertion that DEC could have avoided them by relying on regional merchant combined cycle, hydroelectric plants, and the addition of battery storage at existing North Carolina solar facilities. *Id.* at 51-57. Witness Powers also stated that burning natural gas in steam boilers formerly fired on coal reduces the thermal efficiency of the combustion process and compared the production cost at coal-fired units to approximations of production cost at a combined cycle facility and hydroelectric unit. *Id*.

Sierra Club Direct Testimony

Sierra Club witness Wilson recommended disallowance of all of the Company's capital expenditures made during the time between the Sub 1146 case and the current case. Her recommendation is based on her contention that the net value of each of the coal units was negative for the 2016-2018 time period and that said costs should be disallowed until DEC provides evidence of an analysis demonstrating the value of the investment that was performed at the time the investment decision was made. Witness Wilson also claimed that the coal units only have positive net value in years with extreme weather, and she recommended that DEC consider operating these units seasonally and only during months of peak demand to minimize losses to ratepayers until the plant's retirement dates. Tr. vol. 18, 150, 156-62. Based on her projection of the future energy value of the DEC coal fleet and citing the Georgia Public Service Commission (GPSC) as having taken similar action, she recommended that the Commission cap future capital expenditures intended to prolong the lives of these units and require DEC to obtain Commission approval of any expenditure that exceeds the cap before it can be recovered from customers. *Id.* at 162-67. Witness Wilson acknowledged the advancement of the probable retirement dates of certain units based on the Company's updated depreciation study. *Id.* at 151). She stated that retirement of the entire coal fleet at once would likely lead to reliability issues in DEC's service territory. She suggested that the used and useful standard could be interpreted to mean that if there was a power plant construction project planned in a prudent manner that operates at costs significantly higher than the economic value of the output for reasons beyond the utility's control and ability to reasonably foresee, that plant may be found prudent and used, but not economically useful. *Id.* at 166-68.

Tech Customers Direct Testimony

Tech Customers witness Strunk recommended disallowance of the incremental capital expenditures at Allen Units 4 and 5 and Cliffside Unit 5 between the Sub 1146 case and this case absent further justification of these investments. Focusing on general coal trends and these units' capacity factors, he took issue with these investments in light of DEC's current proposal to accelerate the units' depreciable lives. Tr. vol. 16, 146-51. Witness Strunk also questioned the Company's prior decision not to retire these units early but did not independently assess the retrospective economics of potential retirement decisions. *Id.* at 151-55. Witness Strunk contended that a primary reason for DEC's previous decisions regarding these units was the risk to investors of early retirement, although he recognized the reasonableness of this consideration. *Id.* at 153-54, 156. Witness Strunk acknowledged that much of the Company's recent coal-related investments involved compliance with coal ash regulations but questioned whether earlier retirement of these units could have reduced the amount of these investments. He stated that he has not performed a detailed IRP-type analysis but suggested that DEC could replace a coal unit's energy and capacity with purchased power, surplus capacity, utility-scale renewables, and energy efficiency and demand response. *Id.* at 159-61.

DEC Rebuttal Testimony

With regard to witness Metz's recommended disallowance of the Belews Creek DFO project costs, DEC witness Immel explained that the project is used and useful as it was placed in service on January 10, 2020, and began serving electric power to customers at that time. Tr. vol. 12, 64-66.

Witness Immel also described the voluminous information that DEC provided through discovery in this case in addition to the evidence presented in his direct and rebuttal testimonies. *Id.* at 66, 68-70. Addressing arguments concerning the economic value of the coal fleet, he explained that such contentions fail to recognize the full picture of how DEC dispatches its coal fleet to maximize value for customers, and he noted that witness Wilson's study did not appear to account for the requirement of day-ahead planning reserves. Witness Immel acknowledged that the capacity factors of the coal fleet are declining but explained that DEC requires cycling resources, which operate at lower capacity factors, to provide reliable service to customers in periods of high demand. Witness Immel explained further that a coal unit will provide energy and capacity during the peak and that if a needed coal unit is not online, then the Company must start additional combustion turbines and/or purchase energy and capacity from the market, if capacity is available during such a time. *Id.* at 73-74.

Witness Immel also testified that witness Wilson's forward-looking analysis of the coal fleet is not a valid exercise for a general base rate case. Witness Immel noted that witness Wilson did not explain how her proposed cap on future coal fleet investments would be determined. He testified that these investments were not made to "prolong" the life of particular units but rather to maximize their remaining useful life. Witness Immel stated that the Company cannot recover such costs from customers unless and until the Commission permits it to do so. Finally, he clarified that estimates of future capital investments are not relevant to this proceeding. *Id.* at 75-76.

In response to witness Strunk, witness Immel testified that DEC studied the potential early retirement of Cliffside Unit 5 and Allen Station in 2016 and 2017, respectively, in order to make a timely decision regarding completion of upgrades at those units that were required by state and federal laws and regulations in order to maintain the units' environmental compliance and continue reliably serving customers. Witness Immel stated that given the knowledge the Company had at the time, the studies did not show a compelling economic case for early retirement versus making the required capital investments. Witness Immel concluded that DEC therefore made the prudent decision in both cases to invest in the projects. *Id.* at 70-71. Witness Immel stated that the suggestion that DEC's previous retirement decisions were based primarily on the risk to investors disregarded the many factors considered by the studies, including needed transmission upgrades, replacement power needs, and timing of environmental compliance. Witness Immel also explained that net book value is not part of the economic analysis of early retirement but rather an additional separate consideration, and that the Allen Station retirement study on its own did not support early retirement. *Id.* at 72, 104. Witness Immel noted that DEC's subsequent decision, with the benefit of new and updated information about costs and risks, to propose accelerated depreciation of Allen Units 4 and 5 and Cliffside Unit 5 indicates that the Company is making prudent decisions based on the information available at the time. *Id.* at 73.

In response to witness Powers, witness Immel testified that the DFO project costs were reasonably and prudently incurred. Witness Immel noted that DEC conducted multiple cost-benefit analyses of these projects, which indicated that they would provide the Company and its customers economic value in the form of optionality with fluctuating coal and natural gas commodity prices and resulting lower fuel costs for customers. Regarding efficiency, he explained that while thermal efficiency does decline with DFO, auxiliary load also decreases due to the elimination or reduction of the need for coal processing systems, ash systems, and wastewater treatment systems. Therefore, in response to questions from NC WARN's counsel, he testified that the overall efficiency of the generating unit is minimally impacted. *Id.* at 77-78, 84-85. Witness Immel also explained that the majority of the DFO investment at Cliffside Station was for Unit 6, which can run 100% on natural gas, and that the Company has already realized savings for customers from these projects. *Id.* at 87, 112. On redirect examination, he described the faster ramping capability these projects provide, which in addition to helping DEC follow load throughout the day, helps enable increasing levels of intermittent renewable generation as well as savings related to startup costs. *Id.* at 110-11.

Finally, in response to suggestions that the Company could provide reliable electric service through purchased power and renewable resources without the continued availability of its coal fleet, witness Immel testified that no witness offered a credible and specific explanation of how DEC could have replaced the reliable generation provided by

Belews Creek, Cliffside, or Allen with these resources. Witness Immel stated that neither witness Strunk nor witness Powers credibly challenged DEC's reasonable and prudent decisions to maintain operations at Allen Units 4 and 5 and Cliffside Unit 5 and to invest in the DFO projects. *Id.* at 78-79.

At the hearing in response to questioning by Sierra Club counsel, witness Immel explained that in studying the early retirement of Allen Station and Cliffside Unit 5 in 2016, DEC assumed natural gas fired generation would replace these units because recent IRP filings indicated that was the most economical dispatchable replacement resource. He noted the importance of the voltage support provided by Allen Station during the study timeframe. *Id*. at 92-93, 97-98. Witness Immel clarified that a significant portion of the coal fleet environmental investments would have been required regardless of whether the units were retired, and he testified that even if a variance of such requirements were obtained for Allen Station, the units would not have been able to retire early due to transmission concerns. *Id.* at 100-01. He further noted that witness Wilson's analysis did not consider the capacity value provided by the coal units, even if they are not running. *Id.* at 106-08, 118, 120.

With respect to witness Wilson's testimony regarding the profitability of the coal fleet during peak hours, witness Immel testified that in order to run units during peak hours DEC must maintain them so that they can be available when needed. *Id.* at 120. Addressing the changes in plans for the coal fleet from the time of the earlier retirement studies to this case and going forward, witness Immel stated that DEC continues to look for opportunities to retire coal plants in the most organized fashion with economic benefit to the customer while meeting the state's and the Company's own emissions goals. *Id.* at 121-22. During redirect examination, he testified that the most recent retirement plans for these units support DEC's request for accelerated depreciation of certain units in this case. Witness Immel also testified that no party presented any alternative that DEC could have chosen other than to make the investments in the coal fleet. *Id.* at 122-24.

In response to questions from counsel for the Company, Sierra Club witness Wilson agreed that as DEC transitions away from reliance on coal it must do so while continuing to meet its obligation to provide safe and reliable electric service to customers. Tr. vol. 18, 176. Witness Wilson acknowledged that her study of the economic value of the coal fleet did not analyze what DEC should have done with the information available to it at the time it incurred the costs to maintain these units, did not evaluate what replacement alternatives the Company should have chosen instead of making the investments, and did not identify any particular investment DEC should not have made. Witness Wilson testified that she was not aware of the North Carolina standard for challenging prudence that requires a party to identify specific instances of imprudence and provide a prudent alternative. *Id.* at 177-79. With regard to her testimony on the "used and useful" standard, she could not identify any state commission that had adopted her interpretation of that standard. *Id.* at 183.

Witness Wilson agreed that some of the coal fleet environmental investments were required whether or not the units continued to operate and that if additional environmental improvements had not been made, DEC would have had to shut the units down. Witness

Wilson testified that she did not analyze whether shutting the units down was a feasible path DEC could have chosen and still have been able to meet its service obligations. When asked to illustrate her testimony that retiring all of the units immediately would likely result in reliability issues, she stated that "the lights . . . could potentially go out," and she noted that retiring all of the coal units would not be sufficient to meet peak load plus a required reserve margin. *Id.* at 187-89.

Witness Wilson acknowledged that North Carolina uses a historical test year, updated through a certain time period, to examine reasonableness and prudency of costs. With regard to the case she cited in support for her future investment cap proposal, she agreed that the Sierra Club did not join the stipulation approved by the GPSC and that the nonsigning parties' recommendations in that case were specifically denied. *Id.* at 184-86.

Further, witness Wilson agreed that the results of the 2016 Allen Station retirement study indicated that DEC would have incurred greater costs by retiring the station early than by making the investments required to continue to run it but stated without further explanation that she objected to a number of the input assumptions made in the study. Witness Wilson stated that her analysis did not look at the need for replacement capacity for any of the coal units if they were shut down. She testified that she did not mention the Allen Station study in her testimony, analyze the data provided in the study, or use any of the information DEC provided through discovery to conduct a retirement study for any of the coal units. *Id.* at 197-200.

In response to questioning by Commissioner Hughes regarding how to reconcile her testimony that retirement of the entire coal fleet would lead to reliability issues with her recommendation to categorically exclude all costs of the coal fleet, witness Wilson clarified that her recommendation was to exclude the capital costs until the Company could provide economic analysis showing that the units were cost-effective for customers. *Id.* at 205.

Discussion and Conclusions

Based on the substantial evidence presented by DEC witness Immel, the Commission finds and concludes that the costs associated with the Company's investments in its coal fleet were reasonably and prudently incurred and should be recovered. The Commission further finds and concludes that Sierra Club's recommendation to limit the Company's future investments in its coal units should not be adopted. Finally, the Commission finds and concludes that the costs for the Belews Creek Unit 1 DFO project are properly included in this case as used and useful.

When setting just and reasonable rates the Commission must determine whether costs incurred by the utility were prudently incurred, which involves an examination of whether the utility's actions, inactions, or decisions to incur costs were reasonable based on what it knew or should have known at the time the actions, inactions, or decision to incur costs were made. When challenging prudence the challenger is required to (1) identify specific and discrete instances of imprudence, (2) demonstrate the existence of prudent alternatives, and (3) quantify the effects by calculating imprudently incurred costs. Detailed proof or analysis must also be provided. Order Granting Partial Increase in Rates and Charges, *Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Electric Rates and Charges*, No. E-2, Sub 537, 78 N.C.U.C. Orders & Decisions 238, 251-52 (Aug. 5, 1988); *rev'd, in part*, *and remanded on other grounds, Utils. Comm'n v. Thornburg*, 325 N.C. 484, 385 S.E.2d 463 (1989) (*Harris Order*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). Nevertheless, intervenors have a burden of production if they dispute an aspect of the utility's prima facie case. If the intervenor meets its burden of production through the presentation of competent, material evidence, then the ultimate burden of persuasion reverts to the utility in accordance with N.C.G.S. § 62-134(c). *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982).

The Commission gives substantial weight to the prefiled and hearing testimony of Company witness Immel regarding the prudency of the costs of DEC's investments in its coal fleet. Witness Immel explained in detail how the Company prudently determined that these investments were needed to maintain DEC's remaining active coal units to continue to provide safe, reliable, and cost-effective electric service to customers. He explained that a significant portion of these costs were required under environmental laws or regulations regardless of whether the Company continued to run the units, and that a large portion of the remaining costs were incurred to maintain compliance with environmental requirements to continue to operate the units. Further, no party has offered concrete, specific evidence to contradict DEC's determination that it needed to continue to operate these units to serve customers.

With respect to the DFO projects, witness Immel presented convincing evidence in rebuttal and at the hearing regarding the rationale for these investments, which he testified are already resulting in savings for customers. The Commission places much weight on DEC witness Immel's testimony that the Belews Creek DFO project was placed in service on January 10, 2020, and began providing electric service to customers at that time, thereby being used and useful under the requirement of N.C.G.S. § 62-133(b)(1).

Further, the Commission concludes that no intervenor met its burden of production to challenge the Company's coal fleet investments. Sierra Club witness Wilson's recommended disallowance, as she admitted, is not specific to any particular cost. Moreover, witness Wilson testified that retiring the coal fleet all at once would likely result in reliability issues but did not identify any other prudent alternatives available to the Company. Tech Customers witness Strunk and NC WARN witness Powers, however, directed their disallowance recommendations to particular units but, aside from the DFO projects, did not identify specific costs as being imprudently incurred. In addition, the alternatives they suggested — merchant generation purchases, solar or hydroelectric generation, demand side management — are not supported by any evidence suggesting these were feasible options for the Company. No witness conducted an independent analysis using the information available at the time the Company's investment decisions were made to present evidence supporting a finding that DEC could have made another prudence choice. The evidence in the record clearly demonstrates that the Company made the best investment decisions it could with the information available at the time.

Moreover, the Commission finds persuasive witness Immel's rebuttal of witness Wilson's economic value analysis, which did not consider either the capacity value provided by DEC's coal fleet or how the Company dispatches its system as a whole on a daily basis. The Commission agrees with DEC that isolating costs invested in and the value of energy produced by a particular station on an annual basis does not accurately represent the value of the coal fleet. As witness Immel showed, even units with declining capacity factors are needed during times of high demand. For similar reasons, and because DEC must still invest in a unit to keep it available during high demand periods, the Commission does not find witness Wilson's recommendation that the Company consider operating its units seasonally to be reasonable. Finally, the Commission does not accept witness Wilson's interpretation of the term "useful" in the used and useful standard. Her reading contemplates finding an asset to be "not useful" when it was planned prudently and was impacted by changes outside the utility's control, which is not an interpretation that has been adopted by this Commission.

Finally, witness Wilson quantified her disallowance recommendation on the contention that DEC did not present evidence of the value of the investments at the time they were made. However, as witness Wilson's hearing testimony made clear, she did not consider the evidence in the 2016 Allen Station retirement study pertaining directly to this issue. As shown by witness Immel's prefiled and hearing testimony, including his testimony regarding the volume of data DEC provided to the Public Staff and intervenors in support of coal fleet investments, the Company conducted exhaustive studies of continued investments in Allen Units 4 and 5 and Cliffside Unit 5, and of the DFO projects, and relied on the results of those studies to proceed with the investments it is seeking to recover. The Commission therefore concludes that Sierra Club's contention regarding a lack of evidence is not supported by the record.

The Commission also declines to accept witness Wilson's recommendation to limit the Company's future investments in its coal fleet. Such a limitation is not necessary as the Company cannot recover any future capital investments before seeking and obtaining the Commission's approval in a future proceeding.

Finally, based on witness Immel's rebuttal testimony and witness Metz' supplemental testimony, the Commission finds and concludes that DEC's costs associated with the Belews Creek Unit 1 DFO project resulted in property used and useful and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 19–26

CCR Cost Recovery

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the CCR Settlement between DEC, DEP, the Public Staff, the AGO, and Sierra Club; the testimony and exhibits of DEC witnesses Kerin, Bednarcik, Wells, Williams, Lioy, McManeus, and De May, Public Staff witnesses Junis, Maness, Garrett, Moore, Boswell, AGO witnesses Wittliff and Hart, Sierra Club witness Quarles, and CUCA witness O'Donnell, and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

Witness Kerin

In Sub 1146 witness Kerin provided a detailed history of coal ash regulation and testified that DEC's historical coal ash management practices, those prior to the federal CCR Rule and CAMA, were reasonable, prudent, and generally comported with the industry practice of sluicing wet coal ash to unlined basins, especially in the eastern region of the country. In addition, he testified that the use of unlined basins complied with the applicable federal and state regulations. 2018 Tr. vol. 14, 99-100, 135. He testified that the Clean Water Act of 1972 and the subsequent creation of the National Pollutant Discharge Elimination System (NPDES) permitting system made wet ash handling and ash basins the primary lawful and effective way to meet CCR needs and environmental requirements from 1974 until 2015. *Id*. at 100, 106-09.

Witness Bednarcik

DEC witness Bednarcik provided an overview of the federal and state regulatory requirements applicable to DEC's coal ash basins and landfills, including the CCR Rule and CAMA, similar to that provided by witness Kerin in Sub 1146. Tr. vol. 13, 194-201. She testified that all of the coal ash remediation actions taken by DEC for which it is seeking cost recovery were required by applicable statutes and regulations and were performed in a prudent and reasonable manner. *Id.* at 215-19.

Witness Bednarcik testified that the coal ash basins at Allen, Belews Creek, Buck, Cliffside, and Marshall are classified as low risk under CAMA and, therefore, can be dewatered and closed in place. However, she stated that in April 2019, the North Carolina Department of Environmental Quality (DEQ) ordered DEC to excavate the coal ash basins at Allen, Belews Creek, Cliffside, and Marshall. Witness Bednarcik testified that prior to the DEQ order DEC had not done any site work at these basins that was specific to cap-in-place other than preliminary planning and that the site work to-date would have been required for closure by excavation. *Id.* at 201-04.

Witness Bednarcik testified regarding the activities performed and costs incurred from January 1, 2018, through June 30, 2019, at DEC's eight active coal plants. *Id.* at 204-11. She explained that the Buck plant was selected as one of three Duke Energy sites for a beneficiation project pursuant to CAMA. She stated that DEC will close the impoundments at Buck by excavation and that the coal ash from Buck will be processed through the beneficiation plant for use in the concrete industry rather than being placed in a lined landfill. She stated that DEC selected The SEFA Group, Inc.'s STAR technology to process the coal ash from Buck and that construction of the beneficiation plant began in May 2018, including construction of a sedimentation basin and the foundations and support structures for the beneficiation plant. *Id.* at 207-08.

Witness Bednarcik further testified that in 2014 Duke Energy executed contracts with Charah, LLC, to dispose of coal ash from DEC's Riverbend plant and DEP's Sutton, Cape Fear, H.F. Lee, and Weatherspoon plants. She stated that the contracts required Duke to provide a minimum amount of coal ash and that due to changing circumstances caused by CAMA amendments, Duke did not provide the minimum amount of coal ash to Charah. As a result, Duke incurred a fulfillment charge of $80 million, and $46,329,946 of the fulfillment charge has been allocated to DEC for Riverbend "as well as future estimated costs for leachate management, capping the landfill, and post closure maintenance." *Id.* at 212-13.

AGO Direct Testimony

Witness Wittliff

Witness Wittliff testified in Sub 1146 that based on his professional training and experience, DEC did not operate its coal ash basins in a manner designed to meet environmental regulations and to ensure that the basins were properly managed. 2018 Tr. vol. 11, 230-42. Specifically, he testified that since the 1970s the industry showed a gradual shift away from surface impoundments towards landfills and away from unlined basins to lined waste management units. *Id.* at 252. He further testified that DEC failed to follow this movement, and he stated that in 2017 the Company continued to employ a combination of wet unlined surface impoundments, unlined landfills, and ash stack areas at all of its coal plants. *Id.* On cross-examination in that proceeding, however, witness Wittliff stated that costs incurred by the Company to comply with the CCR Rule were reasonable and prudent, *id*. at 282-83, and he admitted that he did not identify any specific costs that could have been lower or should be disallowed. *Id*. at 287-89.

Witness Hart

In the current rate case witness Hart discussed the CCR Rule, CAMA, the 2L rules, and other environmental guidelines applicable to coal ash basins. Tr. vol. 16, 709-18. Witness Hart testified that unlined coal ash basins cause groundwater contamination. He explained that the metals present in the coal ash leach out of the ash, enter a dissolved state, and become coal ash "leachate," and that because a hydraulic head is maintained in the basin the metals-laden water in the basin migrates downward into underlying soil. *Id*. at 742-47. Witness Hart discussed several industry and government studies and reports, similar to those noted by other witnesses, that he opined placed the electric utility industry on notice of the potential leaching of coal ash metals into groundwater.

Witness Hart provided the details of the coal ash basins and groundwater monitoring at each of DEC's coal plants. In addition, he included graphs for each plant showing the most prominent coal ash constituents. *Id*. at 769-820; AGO Hart Direct Exs. 40-54. Witness Hart concluded that prior to the Dan River coal ash spill DEC did not take reasonable and prudent actions to address groundwater contamination at its coal ash basins and to close the basins. *Id.* at 821-24. Witness Hart testified that DEC's inaction increased its present coal ash remediation costs because the Dan River spill prompted accelerated remediation actions, which are always more costly. Witness Hart attempted to quantify this increased cost and stated that earlier action by DEC would have resulted in cost recovery while the coal plants were still in use, and at a lower cost.

Public Staff Direct Testimony

Witness Junis

In his Sub 1146 testimony, witness Junis testified that DEC and DEP have over 100 million tons of coal ash stored in landfills and basins in North Carolina. He provided a summary of the CCR Rule, CAMA, the 2L standards, and other environmental legislation and regulations. He stated that CCR basins contain certain elements that can pollute groundwater, waterways, and drinking water, including arsenic, boron, lead, aluminum, cadmium, sulfate, and vanadium.

Witness Junis testified that DEC voluntarily installed most of its groundwater monitoring wells in and around 2010 but installed a few at Cliffside and Dan River as early as November 1993. Further, he testified that there were six coal plants where DEC did not monitor groundwater until 2004 or later. *Id*. at 700-03. He stated that violations of 2L standards were detected near on-site landfills as early as 1989 at Belews Creek and Marshall. In addition, based on data request responses from DEC, he testified that as of 2017 all of DEC's North Carolina coal ash basins had groundwater exceedances in violation of the 2L rules. *Id.*; 2018 Junis Direct Ex. 20.

In addition, witness Junis testified that DEC had identified 98 unpermitted seeps at its coal ash basins as of 2014 and later. *Id*. at 704-19; 2018 Public Staff Wright Cross-Exam Ex. 2. He stated that some of the costs for corrective action, which DEC labels as compliance costs to meet the requirements of the CCR Rule and CAMA, are actually for corrective action necessitated by noncompliance with longstanding environmental regulations. *Id*. at 732-37.

Witness Junis stated that the Public Staff believes it is appropriate to assign to DEC the responsibility for costs to defend against environmental violations and costs to remedy those violations, except to the extent that CAMA imposed new requirements that increased the cost of remediation. He stated, however, that there were instances in which DEC's actions were prudent, that separating out the imprudent costs would be complex, and that the calculation of some costs of imprudence would be speculative. Therefore, the Public Staff recommended an equitable sharing, with 50% of the CCR costs being paid by shareholders and 50% by ratepayers. *Id*. at 737-742.

In the present docket, witness Junis reiterated and updated his Sub 1146 testimony. He testified that the Public Staff continues to pursue its 50/50 equitable sharing recommendation and that the equitable sharing proposal is not based on these actions being deemed imprudent. Tr. vol. 20, 406-23, 429-31, 462-67.

Witness Junis described the settlement reached by DEC, DEQ, and several environmental parties on December 31, 2019. He explained that DEC will excavate and move to lined basins most of the coal ash at DEC's Allen, Belews Creek, Cliffside, and Marshall plants, and at DEP's Mayo and Roxboro plants. He testified that excavation and removal has been completed at Dan River and Riverbend, that DEC's Buck plant is a beneficiation project, and that the W.S. Lee plant in South Carolina is not covered by CAMA. *Id*. at 423-27.

Witness Junis concluded his testimony with the Public Staff's recommendations for disallowance of the following costs: (1) costs spent by DEC to install wells for the extraction and treatment of groundwater at Belews Creek; (2) costs to provide bottled water, water connections to municipal or county systems, and water treatment systems; and (3) fines and penalties for environmental violations. He stated that the above disallowances are in addition to those recommended by Public Staff witnesses Garrett and Moore. *Id*. at 455-62.

Witness Maness

In his testimony in the present docket, witness Maness discussed the three coal ash cost adjustments being proposed by the Public Staff: (1) the disallowances recommended by witnesses Junis, Moore and Garrett; (2) an amortization period of 26 years; and (3) the reversal of DEC's inclusion of coal ash costs in rate base. Tr. vol. 20, 495-98.

Witness Maness testified that the Public Staff believes there should be an equitable sharing of the coal ash costs between ratepayers and shareholders. He explained that an equitable sharing can be achieved by, first, excluding the coal ash costs from inclusion in DEC's rate base and, second, using a longer amortization period. *Id*. at 498-507, 514-17. Witness Maness testified that the five-year amortization period proposed by DEC is too short. He stated that the CCRs are the result of decades of generating electricity by coal and that associated costs should be amortized over a similarly lengthy period. The Public Staff, therefore, recommends an amortization period of 26 years.

With respect to DEC's future coal ash costs, witness Maness testified that the Public Staff agrees that DEC should be allowed to defer its future costs in a regulatory asset and accrue a return on the deferred balance at the net-of-tax overall return authorized by the Commission for DEC during the deferral period. *Id*. at 519-20.

Witness Garrett

Witness Garrett, a registered professional engineer and a consultant with the engineering firm Garrett and Moore, testified that he investigated the prudence and reasonableness of the costs DEC incurred at its two high-priority sites under CAMA, Riverbend and Dan River. Witness Garrett stated that Charah was retained to provide disposal capacity at the Brickhaven mine for ash from DEC's Riverbend Station and from DEP's Sutton Station. Based on his investigation witness Garrett recommended that the

Commission disallow certain costs DEC seeks to recover related to the fulfillment fee the Company paid to Charah that are not reasonable and prudent. Tr. vol. 20, 201-04. Witness Garrett further concluded that DEC paid a significant premium for coal ash excavation and disposal at Riverbend regarding work begun by Parsons Environment & Infrastructure Group, Inc., and ultimately completed by Trans Ash, Inc., and he recommended a disallowance related to these costs as not reasonable and prudent. *Id*. Witness Garrett opined that DEC had other more prudent options that would have avoided the additional costs, including: (1) requesting a variance of the CAMA deadline; (2) negotiating new rates with Parsons; (3) having a performance bond with Parsons; or (4) imposing back charges on Parsons for work completed by Trans Ash. *Id.* at 237-41.

Witness Moore

Witness Moore, a registered professional engineer and a consultant with the engineering firm Garrett and Moore, testified that he investigated the prudence and reasonableness of DEC's CAMA compliance costs at Allen, Belews Creek, Buck, Cliffside, and Marshall. He stated that he takes no exception with DEC's CCR costs for work at Allen, Belews Creek, Cliffside, and Marshall. Tr. vol. 20, 168, 172-75.

Witness Moore recommended a disallowance of certain costs incurred in the construction of the Buck beneficiation project. He described the Request for Information (RFI) process by which Duke chose SEFA and SEFA's STAR beneficiation system for DEC's Buck and DEP's Lee and Cape Fear beneficiation projects. He stated that he agrees with Duke's choice of SEFA and does not take exception to the subsequent change orders submitted by SEFA or the costs associated with those change orders. *Id.* at 186-87, 190. However, witness Moore testified that he does not agree with the choice of Zachry Industrial, Inc., as the general contractor. He testified that readily available information shows lower capital costs for a similar SEFA project in South Carolina and opined that Duke could have attempted to mitigate the construction costs by rebidding the contract, entering into three separate construction contracts, obtaining an amendment to CAMA, or obtaining guidance from DEQ. *Id.* at 185-191. Based on his determination that the Company's selection of Zachry to construct the beneficiation unit at the Buck Station for the amount contracted was unreasonable and imprudent, witness Moore recommended that the Commission disallow a portion of the construction costs for the Buck beneficiation facility.

Sierra Club Direct Testimony

Witness Quarles

Witness Quarles testified on behalf of the Sierra Club in both Sub 1146 and the present DEC rate case. Witness Quarles reiterated in this case his testimony in Sub 1146 that the Company "continued to build new unlined disposal areas and expand existing ones through the 1990s, to operate unlined surface impoundments through the present day, and to stack wastes on top of unlined disposal areas — even though utilities around the United States have been constructing lined disposal areas since the mid-1970s and despite an understanding of contamination risks associated with disposal in unlined ponds." Tr. vol. 18, 31-32. He testified further that "[s]ince at least the mid-1970s, it was reasonable for the Company to expect CCR contamination of groundwater and surface waters because of its use of unlined surface impoundments," and that on-going leaching of coal ash constituents from the Company's unlined surface impoundments has resulted in groundwater contamination beneath and downgradient of the disposal areas that has exceeded DEQ and EPA standards. *Id*. at 32.

In the current rate case witness Quarles focused in his testimony on "determining *when* the Company knew or should have known that groundwater or surface water contamination was likely due to storage and disposal of CCRs in unlined areas located near — and even sometimes within — rivers and streams and where the ash is saturated with groundwater." *Id*. at 28. Witness Quarles concluded that DEC's costs to excavate the coal ash and for groundwater monitoring at Allen could have been lower if DEC had converted to dry ash handling sooner. He recommended that the Commission conclude that DEC's continued operation of unlined basins after the industry recognized the risks was unreasonable and that DEC's failure to take action at Allen after its 1984 investigation revealed groundwater contamination was unreasonable. Further, he provided no disallowance recommendation but testified that costs associated with excavation and groundwater monitoring today likely would be lower if DEC had converted to dry ash disposal in lined landfills sooner. *Id.* at 57-59.

CUCA Direct Testimony

Witness O'Donnell

Witness O'Donnell discussed the Dan River spill and DEC's guilty plea for other unauthorized discharges of coal ash pollutants. He cited an early draft of CAMA and statements by legislators to support his contention that Duke's environmental violations caused the General Assembly to enact CAMA, and, therefore, DEC should not be permitted to recover from customers any coal ash costs above those that DEC would have incurred under the CCR Rule. Tr. vol. 20, 59-70.

DEC Rebuttal Testimony

Witness Bednarcik

Witness Bednarcik responded to the Public Staff's contention that DEC's cost of installing extraction wells and treating the groundwater at Belews Creek should be disallowed. She testified that the amount spent by DEC to install wells for the extraction and treatment of groundwater at Belews Creek was incurred for the same purposes as that approved by the Commission for recovery in DEC's previous rate case and should likewise be approved. Tr. vol. 24, 91-93. With regard to DEC's installation of permanent water supplies and water treatment systems, witness Bednarcik stated that this work is required by CAMA and that the costs should be recoverable by the Company. *Id.* at 93-96. With respect to the Public Staff's equitable sharing recommendation, witness Bednarcik testified that this proposal has now been rejected by the Commission three times and that it continues to lack any basis under the standard for recovery of prudent and reasonable costs. *Id.* at 48-49, 96-98.

In response to AGO witness Hart's proposed cost disallowance quantification, witness Bednarcik testified that his quantification implicitly rejects the idea that DEC could have used closure strategies different from today if it had it begun such activities in 1989, 1993, 2003, or 2010. She further testified that it is impossible to retroactively predict with any degree of certainty what options the Company might have pursued had it chosen to close its inactive basins in 1989, 1996, 2003, or 2010 given the historical regulatory landscape, available technology, and evolving industry best practices. Lastly, she stated that as DEC rebuttal witness Lioy discusses, AGO witness Hart's calculations simply show the equivalent of today's closure costs reduced based on rates of inflation. *Id.* at 105-07.

In response to Public Staff witness Garrett's recommended disallowance for costs associated with excavation and disposal at Dan River, witness Bednarcik testified to deficiencies in performance that led to termination of the Parsons contract by DEC. She testified that DEC formally informed Parsons that absent immediate improvement, DEC would be forced to consider termination. She testified that after several meetings with Parsons' executive leadership, Parsons was ultimately unable to demonstrate to the Companies that it was equipped to properly excavate the coal ash basins at Dan River, and particularly not in accordance with CAMA's required timeline. *Id.* at 67.

Witness Bednarcik further testified in response to witness Garrett's contentions about other options that were available to DEC rather than termination of the Parsons contract. She testified that having a performance bond with Parsons and negotiating new rates would not have improved Parsons' performance to the extent needed to meet the CAMA deadline and that there were no grounds for imposing back charges because Parsons did the work properly. She testified that none of Parsons' work had to be redone by Trans Ash. Further, she stated that even if DEC had requested and DEQ had granted a variance from the August 1, 2019 deadline, there was no guarantee that Parsons would have been able to meet the new target date. *Id*. at 66-76.

In response to Public Staff witness Moore's recommended disallowance for the Zachry contract, witness Bednarcik explained that the estimate SEFA provided was based on the costs it incurred to construct the Winyah STAR facility in South Carolina, but that there are several key differences between the Winyah and Buck projects that would impact cost, including: (1) the Winyah plant is designed to produce 200,000 tons of ash product per year (a 120 MMBtu facility), while the Buck project must produce 300,000 tons of ash product per year (a 140 MMBtu facility) to meet CAMA requirements, which requirement necessitated installation of a second external heat exchanger at Buck along with all associated equipment; (2) Winyah typically uses 70% ponded ash and 30% production ash, but ash at DEC's plants is 100% ponded ash and required the addition of a grinding circuit to meet American Society for Testing Materials (ASTM) standards for concrete; (3) the two facilities use different scrubbers, and the dry scrubbers at Buck required a second bag house with additional induced draft fans; and (4) the Winyah facility was a refurbishment/addition to an existing carbon burn-out facility and SEFA was able to reuse a significant part of the carbon burn-out facility when constructing Winyah's plant, whereas the DEC facilities are new construction. Tr. vol. 25, 82-84.

In addition, witness Bednarcik stated that witness Moore's suggestion that the Company should have sought statutory relief from CAMA's beneficiation requirements is not realistic. She stated that there is no guarantee that the General Assembly would have granted such relief and that even if it had been willing to do so, it is likely that the original CAMA deadline would have passed before such a bill could be drafted, vetted, and passed. Likewise, witness Bednarcik testified that witness Moore's suggestion that the Company should have sought guidance from DEQ upon learning of Zachry's estimated costs is also misguided because DEQ is responsible for enforcing the State's environmental laws irrespective of an entity's cost of compliance, and there are no cost considerations in the beneficiation provisions of CAMA. In response to witness Moore's contention that DEC should have rebid the project with a larger pool of potential bidders, witness Bednarcik stated that DEC wanted to contract with a contractor that was currently working with the Companies or had worked with the Companies, and a contractor with a North Carolina presence. With respect to witness Moore's suggestion that the Companies could have selected three different contractors for their three beneficiation projects, she stated that by contracting with Zachry for all three projects DEC was able to realize extensive cost savings through economies of scale. She opined that based on the scope, novelty, and difficulty of the Buck project the costs paid to Zachry were reasonable and prudent. Id. at 86-87.

Witness Wells

DEC witness Wells reiterated much of his testimony in Sub 1146 about the industry and regulatory standards and DEC's compliance with those standards. Tr. vol. 27, 27-32. He noted that the Commission rejected the Public Staff's equitable sharing recommendation in the 2018 DEC Rate Order. He also asserted that no intervenor witness had attempted to quantify alleged imprudent costs caused by DEC's historical management of coal ash. *Id.* at 25-27.

Witness Wells testified that DEC met its responsibility to comply with NPDES permitting requirements. Witness Wells noted that witness Junis suggested that the existence of seeps at DEC's coal ash impoundments is evidence of the Company's "culpability." However, asserted witness Wells, this suggestion ignores the fact that: (1) seeps are a natural and even necessary consequence of earthen impoundments; (2) EPA first directed permitting authorities to address seeps in 2010; (3) the Company made attempts to obtain regulatory certainty as to seeps; and (4) DEQ faced challenges in implementing EPA's directives on seeps. *Id.* at 56-51. Witness Wells testified that DEC has taken a measured and responsible approach, consistent with the rules and regulations, to address potential environmental impacts from its surface impoundments — monitoring and, if needed, taking corrective action to safeguard against impacts to receptor wells, surface water, and offsite property. *Id.* at 35-46.

Witness Wells discussed DEC's agreement with DEQ and cited several other developments that he stated are evidence of DEC's diligence in working with environmental regulators to improve DEC's coal ash facilities, including: (1) the conversion to dry bottom ash handling at Allen, Belews Creek, Cliffside, and Marshall, plus the beginning of decanting at these sites; (2) the submission of Corrective Action Plans to DEQ for Allen, Belews Creek, Cliffside, and Marshall; and (3) completion of excavation and removal of all coal ash at Dan River and Riverbend. *Id.* at 66-69. In response to questions from the Commission, witness Wells testified that it was prudent for DEC to wait until the CCR Rule was final to decide to dispose of coal ash in a manner other than unlined basins. Tr. vol. 28, 124-27.

Witness Williams

Witness Williams, who worked for the EPA for 17 years and served as Director of the Office of Solid Waste until 1988, testified regarding the history of coal ash regulations and the evolution of the CCR Rule. She stated that owners and operators of coal ash basins in North Carolina faced significant uncertainty regarding regulatory requirements until adoption of the CCR Rule and CAMA, and based on these uncertainties, owners and operators of coal ash basins acted prudently by waiting for adoption of the CCR Rule and CAMA to take specific actions to upgrade or close coal ash basins. *Id.* at 104-07. She discussed several factors that compound uncertainty in EPA regulation, including participation of diverse interests, length and complexity of the process, collection of new information, additional analyses required by Executive Orders, changes in administrations, court challenges, and Federal/State interface. *Id.* at 108-14. She stated that DEC did not act imprudently by waiting for regulatory clarity so long as it continued to work with regulatory agencies to address site specific environmental risks. She discussed the efforts made by DEC in the late 1970s and early 1980s to evaluate coal ash constituents and leachate using EPA-sanctioned testing methods, particularly at its Allen and Riverbend plants. Witness Williams stated that DEC took the prudent and appropriate steps to evaluate potential impacts of its coal ash basins on groundwater and surface waters prior to the new requirements included in the CCR Rule and CAMA. *Id.* at 128-39.

With respect to the testimony of witnesses Junis, Quarles, and Hart, witness Williams stated that they failed to consider all relevant information in assessing DEC's historic actions, including selectively using information from studies and reports without considering the broader set of available knowledge on the subject, failing to give appropriate weight to environmental regulations, and failing to assess in detail industry practices in CCR and other waste management. Further, she asserted that they failed to give appropriate weight to the role of DEQ in overseeing DEC's actions. She stated that the fact that DEQ did not require liners, closure of basins, or mandate groundwater monitoring earlier is a strong indication that DEC was managing CCRs in a prudent and reasonable manner. *Id.* at 146-53.

Witness Williams took issue with AGO witness Hart's conclusion that DEC's coal ash remediation costs are higher today than they would be if DEC had been prudent in managing its coal ash. Witness Williams contended that witness Hart's cost disallowance calculations are entirely speculative because there is no way to predict what would or could have been done with respect to coal ash disposal on these earlier dates and how the cost of those activities would compare to the actions that DEC is taking today.

According to witness Williams, Hart's analysis fails to recognize that DEC's coal ash disposal costs could have been higher if DEC had initiated some type of closure action earlier that later proved to be unnecessary or imprudent. *Id.* at 174-84.

Witness Lioy

Witness Lioy testified that AGO witness Hart attempted to quantify the amount that DEC would have spent as of the earlier time periods in his analysis (1989, 1993, 2003 and 2010) in order to quantify alleged imprudently incurred costs. According to witness Lioy, witness Hart did not accomplish that goal because there are a number of factors that would need to be considered to determine what DEC would have spent in 1989, or as of any of the other earlier time periods, including different applicable laws and regulations in 1989, and different technologies, means, and methods available in 1989. *Id.* at 169-72. Witness Lioy concluded that witness Hart's calculations were not prepared in accordance with normal conventions and are unreliable and speculative. *Id.*

Witness McManeus

Witness McManeus testified that the Company opposes the Public Staff's equitable sharing proposal and witness Maness's recommendations to lengthen the amortization for CCR cost recovery and disallow a return during the amortization period. She explained that the Public Staff's equitable sharing adjustment runs directly contrary to well-established ratemaking and cost recovery principles and, in particular, the basic principle that a public utility's reasonable and prudently incurred costs are recoverable in rates. She noted that the Public Staff's approach does not depend on any finding of imprudence but merely adopts an arbitrary amortization period necessary to achieve a 50/50 split of the CCR costs between the Company and its ratepayers. Witness McManeus further testified that it is appropriate for the Commission to allow the Company to recover its financing costs during the amortization period, as the Public Staff acknowledges is appropriate during the initial deferral period. She states that the costs at issue include the cost of money, that the financing costs are related to funds advanced by investors, and that the costs are necessary and prudent to ensure reliable electric service. Lastly, she noted that the Commission rejected the Public Staff's equitable sharing proposal in DEC's 2018 rate case. Tr. vol. 11, 528-33

DEC Settlement Testimony

Witness De May

In support of the January 25, 2021 CCR Settlement witness De May testified that the CCR Settlement represents a balanced solution that resolves the coal ash cost recovery debate in North Carolina, providing both immediate and long-term savings for customers and long-term certainty for the Company and its investors and allowing all parties to move forward towards the desired cleaner energy future. He concluded that the CCR Settlement is in the public interest and should be approved.

Witness De May provided an overview of the CCR Settlement. He testified that it resolves among the Settling Parties, subject to Commission approval, CCR cost recovery issues in both DEP's and DEC's current rate cases and the Companies' prior cases in a comprehensive manner for the period beginning January 1, 2015 (when the Company first incurred such costs), through January 31, 2030 — a period of over fifteen years. Witness De May contended that the CCR Settlement requires the Company to reduce the amount of coal ash-related costs to be recovered from customers and grants the Company the ability to earn a return upon the recovered costs at a negotiated cost of equity lower than the Company's allowed ROE. The CCR Settlement also provides customers with immediate and future rate reduction — DEP and DEC together will absorb approximately $1.1 billion (on a North Carolina system basis) through February 2030. Witness De May testified that on a North Carolina retail basis, the net present value of the cost savings to customers (including applicable financing costs) is in excess of $900 million. Importantly, witness De May noted, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic.

Witness De May also summarized the benefits of the CCR Settlement to the Company. He explained that it "validates and affirms the reasonableness and prudence of [each] Company's ash basin closure strategy," provides more certainty and stability regarding cost recovery, and — by preserving the Companies' ability to recover financing costs, albeit at a reduced rate — preserves their access to much needed capital on reasonable terms, also benefitting customers. Finally, the CCR Settlement — in settling the legacy issue — allows the collective focus to shift to the future to cleaner sources of energy, while maintaining the Company's drive to keep electricity affordable and reliable.

Witness De May explained that the CCR Settlement appropriately balances the need for rate relief with the impact of such rate relief on customers. He stated that the Company is pleased that its rates are competitive and below the national average and will remain so under the CCR Settlement, noting that providing safe, reliable, and increasingly clean electricity at competitive rates is key. Witness De May stated that, particularly in light of the current economic conditions faced by customers due to the COVID-19 pandemic, the Company believes the CCR Settlement fairly balances the needs of customers with the Company's need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service. Given the size of the necessary capital and compliance expenditures the Company faces, it is essential that DEC maintain its financial strength and credit quality for the benefit of our customers.

Witness McManeus

Witness McManeus similarly testified that the Company believes that the CCR Settlement represents a fair, just and reasonable, and balanced solution that provides immediate and long-term savings for customers as well as the long-term certainty the Company and its investors need. Thus, the Company requests that the Commission approve of the CCR Settlement in its entirety. The effect of the CCR Settlement on the Company's requested recovery of CCR costs is shown on McManeus CCR Settlement

Exhibit 1, page NC-1102. As set forth thereon, the CCR Settlement provides for DEC to recover $117,658,176 of actual coal ash basin closure and compliance costs plus financing costs of $51,869,890.

Witness McManeus testified that if the Commission approves the CCR Settlement and the First and Second Partial Stipulations with the Public Staff, the Company's revised request for a revenue increase in base rates is reduced to $357 million. She explained that McManeus CCR Settlement Exhibit 2 shows that the Company's revised request for a revenue increase, combined with the Company's request to reduce customer rates by $295 million through its proposed EDIT rider, results in a net proposed increase in revenue of $62 million — a $229 million reduction from the amount proposed in the Company's Application. She further noted that these amounts assume the Commission accepts the Company's position on the remaining unsettled revenue issues, which are depreciation rates and the appropriate amortization period for the Company's loss on the sale of hydro stations. The other nonrevenue issues concern various forward-looking studies and rate designs.

Public Staff Settlement Testimony

Witness Maness

Witness Maness testified that the CCR Settlement would comprehensively resolve the following CCR cost recovery issues: (1) issues pending before the Commission on remand in the 2018 Rate Cases; (2) issues pending before the Commission in the present rate case proceedings; (3) the treatment of CCR costs incurred by DEC from February 1, 2020, through January 31, 2030, and by DEP from March 1, 2020, through February 28, 2030, along with associated financing costs; and (4) how any proceeds received from insurance litigation related to CCR costs would be shared by ratepayers, DEC, and DEP.

In addition, witness Maness explained that from the perspective of the Public Staff, the most important ratepayer benefits of the Agreement are: (1) DEC's and DEP's agreement to forego the combined recovery of CCR costs and associated financing costs in excess of $900 million, on a present value basis, resulting in a significant reduction in the proposed revenue increase in this case; (2) the allocation of the proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR costs and financing costs into 2030. Accordingly, witness Maness stated that the Public Staff believes the CCR Settlement is in the public interest and should be approved.

Witness Boswell

Witness Boswell provided updated schedules showing the impact of the CCR Settlement. She noted that some final adjustments will have to be made after the Commission's issues its order resolving the remaining unsettled issues.

Public Witness Testimony and Consumer Statements of Position

Over the course of the four public witness hearings held in the instant case, during which a total of 70 public witnesses provided testimony to the Commission, many of the witnesses expressed concerns to the Commission regarding the environmental impact of, the handling of, and the costs associated with CCRs.[3] Similarly, many of the written consumer statements of position filed in this proceeding addressed the issues of the environmental impact of, the handling of, and the costs associated with CCRs.

Discussion and Conclusions

The Commission is required to set just and reasonable rates for public utilities. N.C.G.S. § 62-130(a). Just and reasonable rates are those that provide the utility an opportunity to earn a fair return on its property and are fair to the utility's customers. *State ex rel. Utils. Comm'n v. Piedmont Nat. Gas Co.*, 254 N.C. 536, 119 S.E.2d 469 (1961); *State ex rel. Utils. Comm'n v. Duke Power Co*., 285 N.C. 377, 206 S.E.2d 269 (1974). To achieve just and reasonable rates, the utility's revenue must be sufficient to cover the utility's cost of service, plus allow the utility the opportunity to earn a reasonable return on its rate base but must be fair to customers. To this end, the North Carolina Supreme Court has counselled:

> [T]he fixing of "reasonable and just" rates involves a balancing of shareholder and consumer interests. The Commission must therefore set rates which will protect both the right of the public utility to earn a fair rate of return for its shareholders and ensure its financial integrity, while also protecting the right of the utility's intrastate customers to pay a retail rate which reasonably and fairly reflects the cost of service rendered on their behalf.

State ex rel. Utils. Comm'n v. Nantahala Power & Light Co., 313 N.C. 614, 691, 332 S.E.2d 397, 474 (1985), *rev'd on other grounds*, 476 U.S. 953, 106 S. Ct. 2349, 90 L.Ed.2d 943 (1986), *appeal after remand*, 324 N.C. 478, 380 S.E.2d 112 (1989) (*Nantahala*).

The burden of proof to show that rates are just and reasonable is on the utility. N.C.G.S. § 62-134(c). However, according to the North Carolina Supreme Court,

> [i]n spite of the fact that North Carolina utilities have the burden of proving that the costs upon which their rates are based are reasonable and prudent, the reasonableness and prudence of those costs is "presumed" unless the Commission or an intervenor adduces sufficient evidence to cast doubt upon their reasonableness or prudence, at which point the burden to make an affirmative showing of the reasonableness of the costs in question shifts to the utility. *State ex rel. Utils. Comm'n v. Intervenor Residents of Bent Creek/Mt. Carmel Subdivisions*, 305 N.C. 62, 76, 286 S.E.2d 770, 779 (1982) (*Bent Creek*). In order to satisfy this burden of production, an

[3] Franklin (8/10 witnesses), Morganton (2/5 witnesses), Graham (12/25), Charlotte (18/30).

> intervenor must offer affirmative evidence tending to show that the expenses that the utility seeks to recover "are exorbitant, unnecessary, wasteful, extravagant, or incurred in abuse of discretion or in bad faith or that such expenses exceed either the cost of the same or similar goods or services on the open market or the cost similar utilities pay to their affiliated [utilities] for the same or similar goods or services." *Id.* at 76–77, 286 S.E.2d at 779. If a utility expense is "properly challenged," "[t]he Commission has the obligation to test the reasonableness of such expenses." *Id*. at 76, 286 S.E.2d at 779.

State ex rel. Utils. Comm'n v. Stein, 375 N.C. 870, 908, 851 S.E.2d 237, 261-62 (2020) (second and third alterations in original) (*Stein*). The Supreme Court thereafter held that "the record contain[ed] ample evidentiary support for the Commission's determination in the Duke Energy Carolinas proceeding that the intervenors had failed to elicit sufficient evidence to satisfy the burden of production imposed upon them in *Bent Creek*." *Id*. at 911, 851 S.E.2d at 263.

Finally, the Commission's orders must be based on competent, material, and substantial evidence in the record of the instant proceeding. N.C.G.S. § 62-65(a). Where settlement has been reached by less than all of the parties in a case, as with the CCR Settlement in this case, that settlement should be accorded full consideration and weighed by the Commission along with all other evidence presented in reaching its decision: "The Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *CUCA I*, 348 N.C. at 466, 500 S.E.2d at 703.

The issues related to the recovery of costs incurred to comply with CAMA and the CCR Rule have been highly contentious in the last several electric utility rate cases. The parties to the proceedings have proffered pages and hours of testimony reviewing the history of coal-fired generation and the handling of coal ash throughout the history of the utilities serving North Carolina consumers, comparing the past coal ash handling practices of these utilities to others across the region and the country, debating what different decisions perhaps should have been made and when, and attempting to quantify the impact of such decisions on the CCR costs sought to be recovered from customers. Additionally, the Commission has received significant testimony from public witnesses on these issues. Indeed, coal ash — including environmental impact and associated cost — was the predominant topic at the public witness hearings held in this case.

As noted above, the Public Staff has argued that responsibility for these costs (not otherwise imprudently incurred) should be shared equally between the utility and its customers. Other parties have argued that the utility should bear all or substantially all of the costs of compliance with the recently adopted state and federal requirements. After careful consideration, the Commission determined in DEC's and DEP's 2018 rate cases that the costs incurred, with one exception, were reasonable and prudent but imposed a management penalty in each case, which ultimately reduced the return that each Company would recover during the five-year amortization period.

Upon appeal of the Commission's 2018 rate case orders on this issue, the North Carolina Supreme Court remanded the cases to the Commission for further proceedings to consider the Public Staff's equitable sharing proposal. In summary, the Court concluded

> that the Commission did not err by: (1) allowing the inclusion of a large majority of the utilities' coal ash costs in the cost of service used for the purpose of establishing the utilities' North Carolina retail rates; (2) interpreting N.C.G.S. § 62-133(d) to authorize the Commission, in the exercise of its discretion, to allow a return on the unamortized balance of the deferred operating expenses . . . . On the other hand, we hold that the Commission erred by rejecting the Public Staff's equitable sharing proposal without properly considering and making findings and conclusions concerning "all other material facts" as required by N.C.G.S. § 62-133(d). As a result, we affirm the Commission's decisions, in part, and reverse and remand the Commissions' decisions for further proceedings not inconsistent with this decision, in part.

Stein, 375 N.C. at 946-47, 851 S.E.2d at 286.

The Court's opinion was issued on December 11, 2020 — after the close of the evidentiary record in the instant case. Subsequent to the issuance of the opinion, the CCR Settling Parties — each of which had offered evidence on the issue of CCR cost recovery in the rate cases and had participated in the appeals of the Commission's 2018 rate case orders — worked to reach a compromise on the issues. The CCR Settlement seeks to resolve not only the current DEC rate case but the current DEP rate case, the 2018 rate cases that have been remanded back to the Commission, and future CCR costs to be incurred through January 2030 for DEC and February 2030 for DEP.

On February 12, 2021, upon joint motion of the CCR Settling Parties, the Commission issued an order reopening the evidentiary records, allowing testimony or comments on the CCR Settlement, and allowing requests for hearing by any party. The order made clear that a party's choice not to file a request for a hearing would be deemed by the Commission as a waiver by that party of its right to cross-examine the witnesses who provided testimony regarding the CCR Settlement. No testimony or comments were filed by any party, and no party requested a hearing. Thus, all parties waived their rights to introduce additional testimony or to cross-examine DEC's or the Public Staff's witnesses on their settlement testimony. The Commission will accept the CCR Settlement and the subsequently filed testimony in support of the CCR Settlement into the record of evidence in this case.

The Commission recognizes that the CCR Settlement is the product of give-and-take between the CCR Settling Parties — DEC, DEP, the Public Staff, the AGO, and the Sierra Club. The settlement and supporting testimony by the parties offer an immediate and longer-term resolution of the ratemaking treatment of CCR costs in lieu of the positions previously advocated by the parties. The agreement aims to resolve contentious issues in this and other DEP and DEC rate cases, including the 2018 rate cases, and strikes a balance between the Companies and their customers that all of the CCR Settling Parties found to be appropriate. The Company explains that the CCR Settlement provides benefit to customers through both immediate and future rate reduction — DEC and DEP together will absorb approximately $1.1 billion (on a North Carolina system basis) in CCR-related costs over the time period covered by the CCR Settlement, reducing the amounts they would otherwise seek to recover from customers. On a North Carolina retail basis, the net present value of the savings to customers from forgone CCR cost recovery (including applicable financing costs) amounts to more than $900 million. Importantly, a large portion of the rate reduction will occur over the near term, during a period in which many customers are suffering severe economic hardship from the COVID-19 pandemic. De May Settlement Testimony at 4:11-20. The Commission takes note that the Public Staff generally supports this position, asserting that the agreement obligates DEC and DEP to forego recovery of costs in excess of $900 million (combined DEC and DEP), resulting in a significant reduction in the proposed revenue increase in this case. Maness Settlement Testimony at 5:14-19.

The Commission recognizes that for purposes of this proceeding DEC agrees in the CCR Settlement to reduce the balance of deferred CCR costs to be recovered in this rate case by $224 million. DEC will cease to accrue financing costs on this amount as of December 31, 2020, resulting in additional savings to customers. Additionally, the CCR Settlement provides that DEC will recover the remaining balance of its deferred costs over a five-year amortization period, plus reduced financing costs during the amortization period calculated based on (1) DEC's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation.

For purposes of future rate case proceedings DEC has agreed to reduce the balance of CCR costs to be recovered by $108 million and agrees that this amount shall also cease to accrue financing costs as of December 31, 2020, which provides additional savings to customers. DEC has agreed to recover financing costs during the amortization period established in future proceedings at a reduced rate.

Finally, the Commission notes that the CCR Settling Parties have agreed to waive their rights to challenge future CCR costs on the basis that the Company's historical coal ash management practices were inadequate and led to unreasonable CCR costs being incurred or led to CCR costs being unreasonably higher than otherwise would have been incurred. The CCR Settling Parties reserve their rights only to propose an adjustment to future CCR costs on the grounds that the costs were otherwise unreasonable or were imprudently incurred.

Thus, the CCR Settling Parties in the CCR Settlement settle the ratemaking treatment of CCR costs in this rate case and future rate cases. The agreement aims to reduce costs that are passed on to customers, to avoid additional protracted litigation over the Companies' historical management practices, and to provide some closure to the debate that has been waged for several years. Indeed, the parties to the Companies' rate cases have extensively litigated these contested issues since at least the filing of the 2018 rate cases, and the CCR Settlement seeks to resolve comprehensively certain issues for CCR costs incurred by DEC from January 1, 2015, through January 31, 2030.

While the CCR Settlement is a nonunanimous settlement, the Commission places significant weight on the fact that the Public Staff and the AGO, each of which has litigated the issues associated with CCR cost recovery vigorously in these cases and advocated zealously for consumers, are parties to the CCR Settlement. Moreover, beginning with the 2018 rate cases, the CCR Settling Parties have advocated for significantly different ratemaking treatment for CCR costs, particularly as to how much cost should be borne by customers versus by the Companies. Thus, the Commission recognizes the extent of the compromise and give-and-take that was necessary to achieve consensus on the ratemaking issues. As noted by Public Staff witness Maness, "among the most important benefits provided by the CCR Settlement Agreement are: (1) the agreement of DEC and DEP to forego recovery of CCR Costs and associated Financing Costs in excess of $900 million (combined DEC and DEP), on a present value basis, over the period from January 1, 2015, through January 31, 2030 (DEC), and February 28, 2030 (DEP), resulting in a significant reduction in the proposed revenue increase in this case; (2) the agreement to allocate any proceeds of CCR insurance litigation; and (3) the avoidance of protracted litigation over CCR and Financing Costs into 2030 among the parties to the Agreement and possibly the appellate courts." Maness Settlement Testimony at 5:10-6:3. For these reasons, the Public Staff concluded that the CCR Settlement is in the public interest. Similarly, as noted by Company witness De May, the settlement "represents a balanced solution" that provides both immediate and long-term savings for customers while providing the certainty the Company requires to meet its business needs. Further, witness De May explained that the settlement allows the Company and the CCR Settling Parties to put the debate behind them and move forward to focus on a cleaner energy future. De May Settlement Testimony at 3:8-16. For these reasons, the Company concluded that the CCR Settlement is in the public interest.

CUCA is the one party to the proceeding that presented evidence regarding DEC's CCR costs but did not join the CCR Settlement.[4] CUCA witness O'Donnell testified that the North Carolina legislature passed CAMA in 2014 in response to the Dan River spill and that CAMA is more stringent than the CCR Rule. He recommended that DEC not be allowed to recover CCR costs associated with any plant that is not subject to the CCR Rule but that is subject to CAMA. He further recommended that to the extent any site is no longer receiving coal ash, remediation costs should not be paid for by ratepayers in this case or any future cases. CUCA's position was refuted by the Company in this case. In addition, CUCA's position was previously rejected by the Commission in the DEC

[4] The Commission notes that CUCA is indicated as "not objecting" to the CCR Settlement and did not request an opportunity to present additional evidence on the CCR Settlement or cross-examine the witnesses of the Company or the Public Staff on the CCR Settlement. Joint Motion to Reopen Record, Consolidate Consideration of CCR Settlement Agreement, and for Approval of CCR Settlement Agreement, January 29, 2021.

2018 Rate Order. It was similarly raised by CUCA, refuted by the Company, and rejected by the Commission in DEP's 2018 rate case. These Commission determinations were upheld by the North Carolina Supreme Court in *Stein*. As was the case in the 2018 proceeding, CUCA witness O'Donnell did not quantify any amount that should not be recovered based on the contention that CAMA was enacted in response to the Dan River spill or that CAMA has resulted in the Company's incurring identifiable incremental costs. Rather, he testified simply that consumers should not pay for all of the Company's costs incurred and that the costs should be split equally among the Company and its customers, similar to the recommendation of the Public Staff. However, the Commission notes that the Commission's adoption of the CCR Settlement provides CUCA with its requested relief of a sharing of CCR costs.

In its Order Declining to Adopt Proposed Settlement Rules, the Commission emphasized that "settlements should be encouraged, and that the Commission should do all it lawfully and reasonably can to facilitate the parties' efforts to reach a full and fair settlement." *Rulemaking Proceeding to Consider Proposed Rule Establishing Procedures for Settlements and Stipulated Agreements*, No. M-100, Sub 145, at 10 (N.C.U.C. Mar. 1, 2017). In the instant proceeding, after years of litigation before this body and the courts, the CCR Settling Parties have worked to achieve a settlement of their views and what they perceive to be a full and fair resolution of their disparate positions. In recognition of the foregoing and in light of the evidence in the record, the Commission is persuaded that the compromise embodied in the CCR Settlement is in the public interest. The CCR Settlement appropriately resolves the issues involving the ratemaking treatment of the costs incurred in connection with DEC's management, handling, and remediation of CCRs, including the financing costs incurred while those costs are deferred and while they are being recovered. In addition, the CCR Settlement provides benefits to customers, including a significant reduction in the amount of costs to be recovered by the Company, certainty as to the application of insurance proceeds for customers' benefit, and the avoidance of protracted and expensive litigation regarding the Companies' historical handling of CCRs. The CCR Settlement, which provides significant savings to customers in the near term, also appropriately balances the need for rate relief with the impact of such rate relief on customers in light of the current economic conditions faced by customers due to the COVID-19 pandemic.

At the four public witness hearings conducted by the Commission in this proceeding, a majority of the public witnesses who testified before the Commission expressed concerns regarding the costs and impacts of coal-fired electricity generation. At those hearings, the Commissioners heard first-hand the many perspectives and opinions of customers as to the clean-up of coal ash and the associated costs. Specifically, the following witnesses provided testimony expressing that customers should not bear responsibility for paying for the clean-up of CCRs: (1) in Franklin eight out of the 10 public witnesses, including Estes, Enstrom, Bailey, Bernard, Thomas, Zwinak, Breckheimer, and Uccetta; (2) in Morganton, two out of the five public witnesses, including Wasson, Deal; (3) in Graham 12 out of the 25 public witnesses, including Armijo, Graham, Phillips, Jones, Sanchez, Velez, Cassebaum, Voss, Clapp, Wagner, Smith, Alston; and (4) in Charlotte, 18 out of the 30 public witnesses, including Rose, K. Kneidel, Walsh, S. Kneidel, Henry, Adams, Wells, Goff, Backman, Richardson, Fox, Blanco, De Mallie, Menut, Sparrow, Arevalo, Swaim, Lewin. Tr. vol. 1, 14-25, 28-32, 35-38; tr. vol. 2, 30-35; tr. vol. 3, 17-29, 36-39, 43-48, 51-53, 65-66, 71-73, 78-82, 88-92; tr. vol. 4, 18-20, 24-36, 42-44, 53-57, 62-71, 78-80, 83-94. In addition, those who wrote to express concern emphasized many of the same perspectives. Of the hundreds of statements of consumer position filed in the docket, a majority expressed that customers should not bear responsibility for costs associated with the clean-up of coal ash. *See generally*, Docket No. E-7, Sub 1214CS. Thus, based on the perspectives and concerns consistently expressed by witnesses at the public hearings and in the statements of consumer position filed in the docket, the Commission concludes that the history and legacy of coal-fired electricity generation by the Company is an issue of significant importance to its customers, and their perspectives must be given weight in the Commission's decision-making process. While the CCR Settlement may not go as far as many customers advocated, it strikes a fair balance for customers that the Commission determines will reduce costs (and rates) associated with CCRs, particularly in the near term, and furthers the Company's financial health and access to capital at a reasonable cost.

For these reasons, the Commission concludes that the CCR Settlement is in the public interest and should be approved. Moreover, the Commission concludes that the ratemaking treatment of CCR costs set forth in the CCR Settlement, in conjunction with the other decisions contained within this Order, results in just and reasonable rates for DEC's customers.

Finally, the Commission asked a number of questions at the hearing in this case, including requests for late-filed exhibits analyzing the issue, regarding the possibility of recovering future CCR costs contemporaneously with the expense as an alternative to deferral and amortization, as proposed by the Company in its previous rate case. The Commission notes that the CCR Settlement does not involve such a cost recovery mechanism, opting instead to follow the "spend-defer-recover" method. In accepting and adopting the CCR Settlement, the Commission is not deciding that a cost recovery mechanism that would allow the Company to recover contemporaneously as costs are incurred is without merit. Rather, given the greater certainty that exists with respect to annual costs to be incurred, the Commission sees merit in such an approach, particularly if structured to result in savings to customers. The Commission directs the Company to consider the proper extent to which a contemporaneous cost recovery mechanism could be joined with the "spend-defer-recover" method prior to the next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 27–29

ARO Accounting

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

There has been substantial discussion devoted to the subject of "ARO accounting" in the current proceeding as well as prior DEC proceedings. The Commission will not discuss in detail here the testimony presented by the various parties but will summarize the pertinent facts.

In June 2001 the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards 143, Accounting for Asset Retirement Obligations (SFAS 143), which addressed financial accounting and reporting requirements associated with an entity's legal requirement to retire a long-lived asset. Specifically, SFAS 143 required an entity to recognize the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred if a reasonable estimate of the fair value can be determined. Additionally, upon initial recognition of a liability for an ARO, an entity was required to capitalize an asset retirement cost (ARC) by increasing the carrying amount of the related long-lived asset by the same amount as the liability. This standard was later codified as Accounting Standards Codification 410, Asset Retirement and Environmental Obligations (ASC 410).

In response to the issuance of SFAS 143, on October 30, 2002, the FERC issued a Notice of Proposed Rulemaking to revise the USOA so that FERC accounting requirements would be consistent with those used by FERC-regulated entities for financial reporting purposes. On April 9, 2003, the FERC issued an order amending the USOA. *Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations*, Order No. 631, 103 FERC ¶ 61,021, *reh'g denied*, Order No. 631-A, 104 FERC ¶ 61,183 (2003). Specifically, FERC added new balance sheet and income statement accounts. The FERC ruled that no FERC-regulated entity with formula rate tariffs could include ARO costs in its billing determinations without prior approval. As a FERC-regulated entity, DEC must comply with the USOA. In addition, Commission Rule R8-27 states that the Commission has adopted the FERC USOA as the accounting rules applicable to electric utilities under its jurisdiction subject to certain exceptions and conditions. One such exception is that electric utilities under the jurisdiction of this Commission are required to seek approval to record any items in FERC Account 182.3 – Other Regulatory Assets.

On January 10, 2003, in response to FASB's issuance of SFAS 143, DEC filed a petition in Docket No. E-7, Sub 723 for authority to place certain ARO costs in a deferred account. A request for deferral accounting was necessary so that adoption of SFAS 143 would have "no impact on [DEC's] operating results or return on rate base for North Carolina retail regulatory purposes" such that DEC's "North Carolina retail rate base, net operating income, and regulatory return on common equity" would be the same as they would have been absent the implementation of SFAS 143. Order Granting Motion for Reconsideration and Allowing Deferral of Costs, *Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, No. E-7, Sub 723, at 11-12 (N.C.U.C. Aug. 8, 2003) (Sub 723 Order).

In its Sub 723 Order the Commission required DEC to make a filing setting forth the journal entries it recorded when initially implementing SFAS 143. Further, DEC was required to file annual reports reconciling the account balances in the Company's annual report filed pursuant to Commission Rule R1-32 and the annual North Carolina retail cost-of-service studies filed with the Commission.

On February 18, 2004, DEC filed the required journal entries. As shown therein, at the time of implementation of SFAS 143 the only ARO recorded by DEC was for decommissioning of its nuclear plants. A review of subsequent reconciliation reports shows that it was not until DEC filed its reconciliation report for 2014, after the enactment of CAMA, that there was a significant ARO recorded for steam plant. After the enactment of the CCR Rule, the report for 2015 showed another significant increase in the ARO for steam plant.

DEC's Chief Financial Officer, Brian Savoy, wrote a letter to the Commission dated December 21, 2015 (Savoy Letter), explaining that due to both CAMA and the CCR Rule, the ARO recorded on DEC's books as of November 30, 2015, was approximately $1.84 billion but noted that actual costs to comply with CAMA and the CCR Rule could be materially different. The Company stated that it was not seeking further specific accounting approval at that time but was simply providing an explanation of its accounting for ash basin closure and compliance costs for the Commission's information. DEC stated that only actual costs resulting in cash outlays by the Company related to ash basin closure, plus carrying charges, would result in amounts the Company would seek accounting and rate treatment for in future filings. In the current proceeding, DEC witness Riley explained this concept when he testified that ARO assets and liabilities are presented on a company's balance sheet as a result of accounting journal entries, not from investor or customer contributions, and therefore are not considered for ratemaking purposes until actual costs are expended. Tr. vol. 23, 131.

DEC made such a petition for an accounting order on December 30, 2016, in Docket No. E-7, Sub 1110. In that filing DEC requested approval to defer, in a regulatory asset, costs incurred after January 1, 2015, to comply with federal and state regulations and a return on those costs at the Company's approved weighted cost of capital until the approval of new rates in the Company's next base rate case. DEC stated that from January 2015 through November 2016 the Company had incurred $434.4 million of expenses for state and federal compliance. On July 10, 2017, the Commission issued an order consolidating DEC's request with its then pending general rate case proceeding, Sub 1146.

Prior to seeking rate recovery, the Company's requests and the Commission's decisions were simply intended to ensure that DEC complied with GAAP and FERC accounting requirements but that such compliance did not impact North Carolina retail ratemaking. When DEC requested rate recovery of deferred ash basin closure costs, the issue before the Commission was no longer one of accounting but rather one of ratemaking.

The approval by the Commission of a five-year amortization period for deferred costs in Sub 1146 did not change the Company's requirement to comply with GAAP and FERC. The Company must still record AROs and ARCs; however, for financial reporting purposes those amounts will be adjusted for amounts approved for recovery in rates. This is shown on DEC Late Filed Exhibit 6 where the amount recorded in Account 182.3 – Regulatory Assets "theory" will be transferred to Account 182.3 – Regulatory Assets "spend." The same accounting was set forth in Public Staff Late Filed Exhibit 2.

The Commission reiterates that it will not discuss in detail the various testimony surrounding ARO accounting, ARO-related accounting, deferred expenses, or capitalized costs. The nomenclature applied to the costs which DEC has incurred and will continue to incur in order to comply with both CAMA and the CCR Rule is not pertinent to the ratemaking treatment of such costs. The Commission determined in Finding of Fact No. 65 in the 2018 DEC Rate Order that the Company's request to defer in a regulatory asset account certain costs incurred in connection with compliance with federal and state environmental requirements was reasonable and appropriate. The Commission also determined in that order that DEC expects to incur substantial costs related to coal ash remediation in future years, that it was just and reasonable to allow deferral of those costs, and that the ratemaking treatment of those costs would be addressed in future rate proceedings. The instant proceeding is such a proceeding. The only determination required of the Commission in this proceeding, and future general rate case proceedings, is the prudence of the Company's expenditures and the appropriate ratemaking treatment of such prudently incurred costs. These questions are addressed elsewhere in this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30–35

Capital Structure, Cost of Capital, and Overall Rate of Return

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEC and several parties; and the testimony and exhibits of DEC witnesses D'Ascendis, Newlin, Young, and Fetter, Public Staff witnesses Woolridge and Hinton, AGO witness Baudino, CBD/AV witness McIlmoil, Commercial Group witness Chriss, CIGFUR witness Phillips, CUCA witness O'Donnell, and Tech Customers witness Strunk; and the entire record in this proceeding.

A. Rate of Return on Equity Capital

Summary of the Evidence

In his direct testimony witness D'Ascendis recommended an ROE of 10.50%; however, in its Application, as a rate mitigation measure, the Company requested approval for its rates to be set using an ROE of 10.30% and an overall rate of return of 7.63%. The Company later stipulated to an ROE of 9.75% in individual settlement agreements with Harris Teeter, the Commercial Group, CIGFUR, Vote Solar, NCSEA, and NCJC et al., which is a decrease from the 9.90% ROE and overall rate of return of 7.35% authorized by the Commission in the Company's last rate case, Sub 1146. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation which provides for an ROE of 9.60%. As a result, the HT Stipulation, CG Stipulation, CIGFUR Stipulation, Vote Solar Stipulation, and NCSEA/NCJC et al. Stipulation were each amended as previously described to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

Witnesses for the Public Staff, CIGFUR, the AGO, Commercial Group, Tech Customers, CUCA, and CBD/AV also filed direct testimony on the appropriate ROE to be established in this rate case. This evidence was followed by the Public Staff First and Second Partial Stipulations and the other intervenor settlements, supplemental testimony of Baudino, rebuttal and supplemental rebuttal testimony filed by witness D'Ascendis, settlement testimony filed by DEC witness D'Ascendis and Public Staff witness Woolridge, and finally testimony of witnesses D'Ascendis, Baudino, McIlmoil, and O'Donnell at the consolidated hearing in this matter.[5] In addition to this expert testimony, the Commission received the testimony of a number of public witnesses on DEC's proposed rate increase, as well as numerous statements of consumer position. All of this evidence is summarized below.

DEC Direct Testimony

Company witness D'Ascendis recommended in his direct testimony an ROE of 10.50%, which was the midpoint of his recommended range of 10.00% to 11.00%. Tr. vol. 11, 47. Witness D'Ascendis stated that the ROE, or the cost of equity, is the return that investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return represents the cost of equity capital. Witness D'Ascendis testified the cost of equity is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. Since the cost of equity cannot be directly observed, it must be estimated or inferred based on market data and various financial models. Witness D'Ascendis testified that each of those models is subject to specific assumptions, which may be more or less applicable under differing market conditions. *Id.* at 58-59.

Witness D'Ascendis noted that as all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. *Id.* at 48. He therefore relied on three widely accepted approaches to develop his rate of return on common equity determination: (1) the Constant Growth and Multi-Stage forms of the Discounted Cash Flow (DCF) model, (2) the Capital Asset Pricing Model (CAPM), and (3) the Bond Yield Plus Risk Premium approach. *Id.* He noted, however, weaknesses in the Constant Growth DCF Model, namely that those results are far removed from the returns recently authorized in other jurisdictions and fail to adequately reflect evolving capital market conditions and he therefore discounted those results. *Id.* at 49. The Constant Growth DCF Model produced ROE results ranging from a low of 8.86% to a high of 9.96%, and the Risk Premium-based results, including the CAPM, Empirical CAPM, and Bond Yield Plus Risk Premium methods produced results ranging from a low of 8.68% to a high of 11.10% in connection with one variant of the Empirical CAPM. *Id.* at 56. Finally, the Expected Earnings analysis, which is used to assess the reasonableness of the DCF, CAPM, and Bond-Yield Plus

[5] Tech Customers witness Strunk appeared at the hearing but did not directly address the issue of ROE.

Risk Premium results, produced an ROE estimate with a mean of 10.44% and median of 10.54%. *Id.* at 57. Witness D'Ascendis noted that the FERC uses the Expected Earnings analysis to determine the "zone of reasonableness." Tr. vol. 11, 26.

Witness D'Ascendis provided extensive testimony concerning the capital market environment, *id.* at 107-16, and addressed the effect those market conditions have on the return investors require in order to commit their capital to equity securities. Witness D'Ascendis also focused on capital market conditions as they affect the Company's customers in North Carolina. *Id.* at 97-107. Specifically, his analysis found that the North Carolina and national economies continue to be highly correlated with one another. He concluded therefore that North Carolina conditions "continue to be reflected in the models and data used to estimate the Cost of Equity." *Id.* at 99.

In addition to his econometric models and evaluation of capital market risks, witness D'Ascendis also considered Company-specific business risks in arriving at his final ROE recommendation. These include (1) the risks associated with certain aspects of the Company's generation portfolio, and (2) the Company's significant capital expenditure plan. *Id.* at 81-82.

Regarding economic conditions in North Carolina, witness D'Ascendis noted that North Carolina and the counties comprising DEC's service territory "continue to steadily emerge from the economic downturn that prevailed during 2009-2010 and have experienced significant economic improvement during the last several years." Tr. vol. 11, 106.

Public Staff Direct Testimony

Public Staff witness Woolridge performed DCF and CAPM analyses for both his and witness D'Ascendis' proxy groups of electric utilities. Witness Woolridge developed his DCF growth rate after reviewing 13 growth rate measures, including historic and projected growth rate measures, and evaluating growth in dividends, book value, earnings per share (EPS), and growth rate forecasts from Yahoo, Reuters, and Zack's. Tr. vol. 17, 93, 135. Witness Woolridge applied the DCF model and CAPM which yielded the following results:

- Discounted Cash Flow (DCF) – Electric Proxy Group
  - 8.25% Equity Cost Rate
- DCF – D'Ascendis Proxy Group
  - 8.4% Equity cost rate
- CAPM – Electric Proxy Group and D'Ascendis Proxy Group
  - 6.9% Equity Cost Rate

Id. at 161.

In witness Woolridge's CAPM analysis, he used for the risk-free interest rate the top end of the range of yields on 30-year U.S. Treasury bonds over the 2013-2020 time period, 3.75%. *Id.* at 147. He used the Value Line Investment Survey betas of 0.55 for both his and witness D'Ascendis' proxy groups. *Id.* at 149. Witness Woolridge's market risk premium was 5.75%, which gave most weight to the market premium estimates of KPMG, CFO Survey, Duff & Phelps, the Fernandez survey, and Damodaran. He testified that his 5.75% value is a conservatively high estimate of the market risk premium. *Id.* at 160.

Witness Woolridge concluded that the appropriate equity cost rate for companies in his and witness D'Ascendis' proxy groups is in the 6.90% to 8.40% range. *Id.* at 162. However, witness Woolridge took into account the fact that his range was below the authorized ROEs for electric utilities nationally and made a primary recommendation of a 9.00% ROE, assuming a 50% common equity ratio. Witness Woolridge also provided an alternative recommendation of an 8.40% ROE based on the Company's originally requested capital structure of 53% equity and 47% debt. *Id.* at 219.

Witness Woolridge did not perform an ECAPM analysis. He testified that the ECAPM is an ad hoc version of the CAPM. *Id.* at 180.

Witness Woolridge also testified as to current capital market conditions as of the date of his testimony in February 2020. He stated that although the Federal Reserve increased the Federal Funds rate between 2015 and 2018, interest rates and capital costs remain at low levels. Witness Woolridge also pointed out that in 2019 interest rates fell dramatically with moderate economic growth and low inflation, while the Federal Reserve cut the federal fund rate in July, September, and October and the 30-year yield traded at all-time low levels. *Id.* at 91.

Witness Woolridge responded to witness D'Ascendis' assessment of the economic conditions in North Carolina. He generally agreed with witness D'Ascendis' general conclusion that economic conditions in North Carolina have improved since the Company's last rate case. Witness Woolridge stated that "[a]s highlighted by the correlations between U.S. and North Carolina economic data . . . economic conditions have improved with the overall economy over the past decade." Tr. vol. 17, 211. He argued, however, that although economic conditions generally have improved, other conditions such as the higher unemployment rate in the DEC service territory and the state compared to the United States, a median household income in North Carolina that is lower than the national figure, and the greater than 100 basis point difference in DEC's requested ROE and the average authorized ROEs for electric utilities in 2018-2019, do not support the Company's proposed ROE. *Id.* at 96. Specifically, he noted that while the unemployment rates in North Carolina and DEC's service territory have fallen by two-thirds since their peaks in the 2009–2010 period, they are both above the national average of 3.90%, and that while North Carolina's residential electric rates are below the national average, the median household income is more than 10% below the U.S. norm. *Id.*

AGO Direct and Supplemental Testimony

AGO witness Baudino proposed an ROE of 9.00% based on a capital structure comprising 51.50% equity and 48.50% long-term debt. Witness Baudino's recommendation was based upon his DCF-based market approaches along with the CAPM approach. Tr. vol. 16, 318-19. Witness Baudino later provided supplemental direct testimony where he updated interest rates and market data "since the beginning of March 2020, when concerns about the COVID-19 pandemic began to roil financial markets with extreme volatility." *Id.* at 382. Witness Baudino testified regarding the recent volatility in the markets, including "sharp increase in betas for the companies in the proxy group" *Id.* at 391) resulting in a higher DCF ranging from 8.29 to 9.28, an increase from his initial DCF range of 8.21 to 9.02. *Id.* at 390, Tr. vol. 2, 128. Likewise, witness Baudino testified that nationally, the real gross domestic product (GDP) "declined in the first quarter of 2020 by -5.0%, according to the Bureau of Economic Analysis." Tr. vol. 16, 394. Nevertheless, he continued to recommend a 9.00% ROE in his supplemental direct testimony.

In his direct testimony witness Baudino testified that his 9.00% ROE recommendation was "reasonably close to recently allowed ROEs." Tr. vol. 16, 352. As a reference point to determine "reasonably close" he relied upon average public utility commission allowed ROEs during 2016, 2017, 2018, and 2019 Tr. vol. 2, 135-37) which he calculated as 9.60%, 9.68%, 9.56%, and 9.57%, respectively. Tr. vol. 16, 351.

CUCA Direct Testimony

Witness O'Donnell proposed an ROE of 8.75%, primarily based upon DCF modeling and CAPM methodologies, as well utilizing a comparable earnings approach. Tr. vol. 20, 135-36. Witness O'Donnell's DCF analysis results ranged from 7.0% to 10.0% with a midpoint of 8.50%, his CAPM analysis ranged from 5.0% to 7.0% with a midpoint of 6.50%, and his comparable earnings analysis ranged from 9.25% to 10.25% with a midpoint of 9.75%. *Id.* at 136. He believed that the midpoint of his DCF was the most accurate representation of market conditions as supported by his CAPM analysis but chose a return in the upper end of his DCF range based on allowed returns from other jurisdictions. *Id.*

Commercial Group Direct Testimony

While he did not provide an ROE analysis in his testimony, witness Chriss for the Commercial Group testified that the Company's proposed ROE was significantly higher than rates previously approved by the Commission from 2016 to present, including the prior rate case in 2017. Tr. vol. 16, 69. Likewise, witness Chriss indicated that the Company's proposed ROE is significantly higher than most reported ROE decisions by utilities commissions from 2016 to the present. *Id.* at 70-71. He testified that according to S&P Global Market Intelligence, 148 decisions were rendered over that time frame, with results ranging from 8.43% to 11.95%, and the median authorized ROE was 9.60%. *Id.* at 70. Removing distribution-only utilities and distribution service rates from the analysis, he testified that the average ROE for vertically integrated utilities authorized from 2016 through the time of his direct testimony filing was 9.75%, and the trend in these averages has been relatively stable. *Id.* at 70-71. As previously noted, the Commercial Group subsequently entered into a settlement agreement wherein the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, the parties agree that the provisions of their agreement on the ROE and capital structure shall have been fulfilled.

CIGFUR Direct Testimony

CIGFUR witness Phillips testified that DEC's requested ROE of 10.30% is unreasonable and should be rejected. Tr. vol. 22, 97. He presented evidence that the national average authorized ROE for vertically integrated electric utilities is currently 9.73%. *Id.* He recommended that a reasonable ROE for DEC should not exceed the current national average for vertically integrated electric utilities. *Id.* Similar to the Commercial Group, CIGFUR subsequently entered into a settlement agreement where the parties agreed to a 9.75% ROE that was subsequently amended to provide that if the Commission authorized a 9.60% ROE, CIGFUR would agree that the provisions of its agreement on ROE and capital structure shall have been fulfilled.

CBD/AV Direct Testimony

CBD/AV witness McIlmoil recommended an ROE of "no greater than 9.2 percent" based on a 52/48 capital structure, as approved for Dominion Energy Virginia by the Virginia State Corporation Commission (VSCC) in November 2019. Tr. vol. 16, 587. He recommended that the Commission make consideration of customers' energy burden a priority factor in determining an allowed ROE. *Id.* At the hearing in his summary, witness McIlmoil lowered his recommended ROE to 9.00%. Tr. vol. 10, 125.

Tech Customers Direct Testimony

Tech Customers witness Strunk recommended a lower allowed ROE in line with lower-risk utilities. *Id.* at 145. He opined that witness D'Ascendis' recommendation of 10.50% evidenced witness D'Ascendis' inflation of the ROE. *Id.* at 137. Similarly, witness Strunk testified that witness D'Ascendis' proposed ROE is at the top of the range of allowed returns for other vertically integrated utilities. *Id.* at 139. Witness Strunk likewise asserted that witness D'Ascendis assigned a higher risk to the Company than that of his proxy group. *Id.* at 138.

DEC Rebuttal Testimony

Witness D'Ascendis responded to and discussed in detail the intervenor witnesses' criticisms of his ROE conclusions and recommendations. He indicated that "none of their arguments caused me to revise my conclusions or recommendations." Tr. vol. 1, 46. Witness D'Ascendis stated that "financial models are important tools in determining returns and appreciate[s] that because all models are subject to assumptions, no one method is most reliable at all times, and under all conditions," and therefore it "remains critically important to apply reasoned judgment to determine where the Cost of Equity falls within that model's range of results." Tr. vol. 11, 151.

Generally, witness D'Ascendis advised that over the last five years nearly all authorized ROEs for vertically integrated electric utilities have been above the intervenor witnesses' recommendations. *Id.* at 149. Witness D'Ascendis also included as Chart 1 of his rebuttal testimony a comparison of authorized ROEs for other vertically integrated utilities from 2015 through 2020 that he testified shows that the intervenor witness recommendations are far below the ROEs available to other such utilities.[6] Tr. vol. 11, 150.

Witness D'Ascendis indicated that the "significant departure" represented by the recommendations of witnesses Baudino, O'Donnell, and McIlmoil raises two concerns. First, DEC must compete with other companies, including utilities, for long-term capital needed to provide safe and reliable utility service, and such competition means that the Company would be at a disadvantage in the capital markets if the Commission were to approve an ROE in the ranges recommended by witnesses Baudino, O'Donnell, and McIlmoil. As a result, he testified a likely outcome would be increasing reluctance on the part of investors to provide capital at reasonable costs and terms. Witness D'Ascendis also noted that while they are not exclusively relied upon, authorized ROEs provide observable and measurable benchmarks against which return recommendations may be assessed. *Id.* at 150-51)

Witness D'Ascendis challenged witness O'Donnell's application of the Constant Growth DCF and subsequent recommendation for an ROE of 8.75%. *Id.* at 292. Witness D'Ascendis explained that the reliance on historical growth rates by witnesses O'Donnell and Baudino as part of their Constant Growth DCF modeling does not adequately encapsulate how the model is a forward-looking measure of investors' expectations and there is support that future growth is superior to that of historically oriented growth measures. In response to Witness O'Donnell's contention that the DCF approach is "far superior to all the models now used by practitioners" Consolidated Tr. vol. 3, 26, witness D'Ascendis contended that no support was offered for that assertion. In response to witness O'Donnell's use of the Retention Growth Model, witness D'Ascendis tested the relationship between retention ratios and future growth rates and demonstrated that earnings growth actually *decreased* as the retention ratio increased. Tr. vol. 11, 301. Witness D'Ascendis testified that the CAPM addresses comparable risk in a way that the DCF-based methods do not; the Beta coefficient reflects "systematic" risk which provides a direct measure of relative risk. *Id.* at 311.

Regarding witness McIlmoil's recommended ROE, witness D'Ascendis noted that this was an ROE approved for Dominion Energy Virginia by the VSCC in November 2019, which was a Rate Adjustment Clause hearing and not a general rate case. *Id.* at 337. Moreover, witness D'Ascendis noted that witness McIlmoil failed to acknowledge that the framework in Virginia also includes an earning sharing mechanism of a 70-basis point dead band around the 9.2% ROE. *Id.* at 338. Witness D'Ascendis testified that the current authorized ROE for Dominion Energy Virginia's general rate base assets is 10.00%, and this Commission recently authorized a 9.75% ROE for Dominion's North Carolina operations. *Id.* at 337-38.

Additionally, witness D'Ascendis testified that the intervenor witnesses fail to recognize the risks faced by the Company, and their recommended ROEs do not appropriately reflect the evolving capital market environment. *Id.* at 148. To illustrate his

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[6] The chart prepared by witness D'Ascendis reflects witness Woolridge's original 9.00% ROE recommendation.

point that an ROE in the range recommended by Baudino, O'Donnell, and McIlmoil would risk devaluing the Company's equity and, thus, ability to compete for capital, witness D'Ascendis provided an example of a recent rate decision for CenterPoint Energy Houston Electric in which the financial community responded negatively to an adverse regulatory outcome. *Id.* at 153.

Witness D'Ascendis also provided supplemental rebuttal testimony to update his ROE models and respond to the supplemental direct testimony of AGO witness Baudino regarding current and expected capital markets and their effect on the cost of equity.

Witness D'Ascendis testified that as a result of the COVID-19 pandemic, economic conditions deteriorated in North Carolina in the first half of 2020, as have economic conditions across the country. Tr. vol. 11, 374. Witness. D'Ascendis noted that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally and therefore continue to be reflected in the analyses used to determine the ROE. Tr. vol. 11, 364. In addition, witness D'Ascendis testified that the current level of volatility, which is 50% higher than normal levels, is expected to persist until at least the end of 2021. *Id.* at 362.

Witness D'Ascendis addressed several of the conclusions in witness Baudino's supplemental testimony having to do with how the market upheaval had led to lower Treasury and utility bond yields and higher beta coefficients, and utility companies' stability of operations and credit metrics in response to the turmoil. *Id.* at 347. He responded to each and concluded that none of witness Baudino's arguments resulted in a revision of witness D'Ascendis' conclusions or recommendations. He further concluded that the market turmoil left risk higher than it had been previously and testified that the change must be reflected in the investor-required return. *Id.* at 362-63.

Witness D'Ascendis updated his ROE analyses based on market data as of June 30, 2020, resulting in a DCF ranging from 7.76% - 9.67%, a CAPM ranging from 10.19% - 15.70%, an ECAPM ranging from 10.94% - 15.70%, a Bond Yield Risk Premium ranging between 9.96% - 10.25%, and an Expected Earnings ranging between 5.5% - 13.5%. *Id.* at 344-45, D'Ascendis Supplemental Exs.1-6.

Stipulations

As discussed above, in separate stipulations with CIGFUR, Commercial Group, and Harris Teeter, the Company stipulated to an ROE of 9.75%, along with a number of other provisions representing substantial give and take between the parties. Subsequently, the Company and the Public Staff executed the Second Partial Stipulation, which among other things, provided for an ROE of 9.60%. Thereafter, the other intervenor settlements were amended to provide that if the Commission enters a final order in this docket approving a rate of return of 9.60% to be applied to a common equity component of the ratemaking capital structure consisting of 52% equity and 48% long-term debt, those parties would agree that the provisions of their settlement agreements concerning the ROE and capital structure have been fulfilled.

DEC Settlement Testimony

Witness D'Ascendis provided settlement supporting testimony, in which he supported the Second Partial Stipulation reached between the Public Staff and the Company, explaining that though the stipulated ROE of 9.60% is somewhat below his recommended range, he recognizes that the settlement represents negotiation by the parties of otherwise contested issues and that the Company believes that the Second Partial Stipulation's ROE and capital structure "would be viewed by the rating agencies as constructive and equitable." Tr. vol.11, 368-69. He noted that since 2016 the average authorized ROE for vertically integrated electric utilities has been 9.74%, and that among jurisdictions like North Carolina that are as seen as having constructive regulatory environments, the average authorized ROE was 9.91%. *Id.* at 370-72. Witness D'Ascendis also testified that economic conditions in North Carolina, which deteriorated in the first half of 2020, remain highly correlated to the overall conditions nationwide. *Id.* at 374. He noted that while the 9.60% stipulated ROE "is somewhat below the lower bound of my recommended range," *id.* at 368, as discussed throughout his other testimony "capital market conditions became quite volatile as a result of the COVID-19 pandemic" and as a consequence, "the models used to estimate the Cost of Equity produce a wide range of estimates." *Id.* at 369. Witness D'Ascendis noted, "From January 2016 to June 2020, the average authorized ROE for vertically integrated electric utilities was 9.74%, 14 basis points above the Stipulated ROE. Of the 107 cases decided during that period, 64 (*i.e.*, nearly 60%) included authorized returns of 9.60% or higher." *Id.* at 370. He concluded that the 9.60% stipulated ROE is "a reasonable resolution of an otherwise contentious issue." *Id.*

Public Staff Settlement Testimony

In his testimony supporting the Second Partial Stipulation, Public Staff witness Woolridge testified that he found the cost of capital components reasonable within the context of the overall settlements and in resolution of most of the issues in the proceeding. Tr. vol. 17, 225-28. He noted that the stipulated ROE was a compromise for each party, a reduction from the Company's last authorized ROE of 9.90%, below the 9.67% average authorized ROE for vertically integrated electric utilities during the first half of 2020, and the lowest ROE authorized for a vertically integrated investor-owned electric utility in North Carolina in at least the last 30 years. *Id.* at 229-30.

Hearing Testimony

Under cross-examination by the AGO, witness D'Ascendis noted that measures of volatility had fallen since March but remained high and were expected to continue to remain high. Consolidated Tr. vol. 2, 43-44. Witness D'Ascendis further testified that the North Carolina economy's response to the pandemic was highly correlated with that of the country but that the effect had been somewhat less severe and the recovery had been somewhat more rapid. He concluded that North Carolina was somewhat less affected by the recession than the nation as a whole. Consolidated Tr. vol. 1, 125-26.

Public Witness Testimony and Consumer Statements of Position

The Commission also received hundreds of consumer statements of position in this docket, many of which expressed concern about DEC's proposed rate increase. The Commission held four hearings throughout the Company's North Carolina service territory in order to receive testimony from the Company's customers. A total of 71 individuals testified and at least 60 were DEC retail customers, almost 20 of whom testified that the rate increase was not affordable for many customers, including those on fixed incomes, the elderly, people with disabilities, the unemployed and underemployed, and the poor.

Law Governing the Commission's Decision on ROE

The ROE is often one of the most contentious issues to be addressed in a rate case, even in a case such as this one in which the Second Partial Stipulation and the other intervenor settlements have been reached. In the absence of a settlement agreed to by all the parties, the law of North Carolina requires the Commission to exercise its independent judgment and arrive at its own independent conclusion as to the proper ROW. *See, e.g., CUCA I,* 348 N.C. at 466, 500 S.E.2d at 707. In order to reach an appropriate independent conclusion regarding the ROE, the Commission must evaluate the available evidence, particularly that presented by conflicting expert witnesses. *State ex rel. Utils. Comm'n v. Cooper*, 366 N.C. 484, 491-93, 739 S.E.2d 541, 546-47 (2013) (*Cooper I*).

The baseline for establishment of an appropriate ROE are the constitutional constraints established by the decisions of the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission,* 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) (*Hope*), which establish:

> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting [an ROE], the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital.

2018 DEC Rate Order at 50; s*ee also, State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972) (*General Telephone*). As the North Carolina Supreme Court held in *General Telephone*, these factors constitute "the test of a fair rate of return declared" in *Bluefield* and *Hope*. *Id.*

The ROE is, in fact, a cost. The return that equity investors require represents the cost to the utility of equity capital:

> [T]he cost of capital to the utility is synonymous with the investor's return, and the cost of capital is the earnings which must be generated by the

> investment of that capital in order to pay its price, that is, in order to meet the investor's required rate of return.

Morin, Roger A., *Utilities' Cost of Capital* 19-21 (Public Utilities Reports, Inc. 1984). "The term 'cost of capital' may [also] be defined as the annual percentage that a utility must receive to maintain its credit, to pay a return to the owners of the enterprise, and to ensure the attraction of capital in amounts adequate to meet future needs." Phillips, Charles F., Jr., *The Regulation of Public Utilities* (Public Utilities Reports, Inc. 1993), at 388.

Long-standing decisions of the North Carolina Supreme Court have recognized that the Commission's subjective judgment is a necessary part of determining the authorized ROE. *State ex rel. Utils Comm'n v. Public Staff-N.C. Utils. Comm'n,* 323 N.C. 481, 490, 374 S.E.2d 361, 369 (1988) (*Public Staff*). Likewise, the Commission has observed as much in exercising its duty to determine the ROE, noting that such determination is not made by application of any one simple mathematical formula:

> Throughout all of its decisions, the [United States] Supreme Court has formulated no specific rules for determining a fair rate of return, but it has enumerated a number of guidelines. The Court has made it clear that confiscation of property must be avoided, that no one rate can be considered fair at all times and that regulation does not guarantee a fair return. The Court also has consistently stated that a necessary prerequisite for profitable operations is efficient and economical management. Beyond this is a list of several factors the commissions are supposed to consider in making their decisions, but no weights have been assigned.
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> The relevant economic criteria enunciated by the Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough: (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments in other enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed public utilities.
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> In reality, the concept of a fair rate of return represents a "zone of reasonableness." As explained by the Pennsylvania commission:
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> > There is a range of reasonableness within which earnings may properly fluctuate and still be

> > deemed just and reasonable and not excessive or extortionate. It is bounded at one level by investor interest against confiscation and the need for averting any threat to the security for the capital embarked upon the enterprise. At the other level it is bounded by consumer interest against excessive and unreasonable charges for service.
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> As long as the allowed return falls within this zone, therefore, it is just and reasonable. . . . It is the task of the commissions to translate these generalizations into quantitative terms.

Charles F. Phillips, Jr., *The Regulation of Public Utilities,* 3d ed. 1993, 381-82. (Notes omitted.)

Order Granting General Rate Increase, *Application of Carolina Power & Light Co., d/b/a Progress Energy Carolinas, Inc., for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1023, at 35-36 (N.C.U.C. May 30, 2013), *aff'd*, *State ex rel. Utils. Comm'n v. Cooper*, 367 N.C. 444, 761 S.E.2d 640 (2014) (2013 DEP Rate Order).

Moreover, in setting rates the Commission must not only adhere to the dictates of both the United States and North Carolina Constitutions, but as has been held by the North Carolina Supreme Court, it must set rates as low as possible consistent with constitutional law. *Public Staff,* 323 N.C. at 490, 374 S.E.2d at 370. Further, the North Carolina General Assembly has provided that the Commission must also set rates employing a multi-element formula set forth in N.C.G.S. § 62-133. The formula requires consideration of elements beyond just the ROE element, and it inherently necessitates that the Commission make many subjective determinations, in addition to the subjectivity required to determine the ROE. The subjective decisions the Commission must make as to each of the elements of the formula can and often do have multiple and varied impacts on all of the other elements of the formula. In other words, the formula elements are intertwined and often interdependent in their impact to the setting of just and reasonable rates.

The fixing of a rate of return on the cost of property used and useful to the provision of service (as determined through the end of the historic 12-month test period prior to the proposed effective date of a requested change in rates and adjusted for proven changes occurring up to the close of the expert witness hearing) is but one of several interdependent elements of the statutory formula to be used in setting just and reasonable rates. *See* N.C.G.S. § 62-133. North Carolina General Statute § 62-133(b)(4) provides, in pertinent part, that the Commission shall:

> [f]ix such rate of return on the cost of the property . . . as will enable the public utility by sound management [1] to produce a fair return for its shareholders, *considering changing economic conditions and other factors* . . . [2] to maintain

> its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and [3] to compete in the market for capital funds on terms that are reasonable and that are fair to its customers and to its existing investors. [Emphasis added.]

The North Carolina Supreme Court has interpreted the above-emphasized language as requiring the Commission to make findings regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility. *Cooper I*, 366 N.C. at 495, 739 S.E.2d at 548. The Commission must exercise its subjective judgment so as to balance two competing ROE-related factors — the economic conditions facing the Company's customers and the Company's need to attract equity financing on reasonable terms in order to continue providing safe and reliable service. 2013 DEP Rate Order at 35-36. The Commission's determination in setting rates pursuant to N.C.G.S. § 62-133, which includes the fixing of the ROE, always takes into account affordability of public utility service to the using and consuming public. The impact of changing economic conditions on customers is embedded in the analyses conducted by the expert witnesses on ROE, as the various economic models widely used and accepted in utility regulatory rate-setting proceedings take into account such economic conditions. 2013 DEP Rate Order at 38. Further,

> [t]he Commission always places primary emphasis on consumers' ability to pay where economic conditions are difficult. By the same token, it places the same emphasis on consumers' ability to pay when economic conditions are favorable as when the unemployment rate is low. Always there are customers facing difficulty in paying utility bills. The Commission does not grant higher rates of return on common equity when the general body of ratepayers is in a better position to pay than at other times . . . .

Id. at 37. Economic conditions existing during the modified test year, at the time of the public hearings, and at the date of the issuance of the Commission's order setting rates will affect not only the ability of the utility's customers to pay rates but also the ability of the utility to earn the authorized rate of return during the period the new rates will be in effect. However, in setting the ROE, just as the Commission must assess the impact of economic conditions on customers' ability to pay for service, it likewise must assess the effect of regulatory lag on the Company's ability to access capital on reasonable terms.[7] The Commission sets the ROE considering both of these impacts taken together in its ultimate decision fixing a utility's rates.

Thus, in summary and in accordance with the applicable law, the Commission's duty under N.C.G.S. § 62-133 is to set rates as low as reasonably possible to the benefit of the customers without impairing the Company's ability to attract the capital needed to provide safe and reliable electric service and recover its cost of providing service.

[7] Regulatory lag can cause a utility's realized, earned return to be less than its authorized return, negatively affecting the shareholder's return on investment as other expenses and debts owed are paid ahead of investor return.

Discussion and Application of Law to the Facts

The Commission has examined the Company's Application and supporting testimony and the exhibits and Form E-1 filings seeking to justify its requested increase. DEC's updated request prior to entering into the stipulations and including the May 2020 Updates was an increase of approximately $414.5 million in annual retail revenues.[8] The Public Staff, which in this docket represents all users and consumers of the Company's electric service, and DEC entered into a stipulation on ROE and capital structure that resulted in reducing the retail revenue increase sought by the Company by $92 million. McManeus Second Settlement Ex. 3. CIGFUR, Commercial Group, Vote Solar, and Harris Teeter each entered into a separate stipulation that, as amended, accepted a 9.60% ROE, subject to certain conditions. As with all settlement agreements, each party to the stipulations gained some benefits that it deemed important and gave some concessions for those benefits. Based on DEC's Application, it is apparent that the stipulations tie the 9.60% ROE to substantial agreed upon concessions made by DEC. As noted above, since the AGO, CUCA, CBD/AV, and the Tech Customers, as well as other parties that did not provide testimony on ROE did not agree to the settlements, the Commission is required to examine the stipulations and exercise its independent judgment to arrive at its own independent conclusion as to the proper ROE.

The starting point for an examination of what constitutes a reasonable ROE begins with the various economic and financial analyses provided by the parties' expert witnesses. In this proceeding, those analyses were provided in the testimonies of eight different witnesses. These testimonies, as summarized above, provide a relatively broad range of methods, inputs, and recommendations regarding the proper ROE determination for DEC. For example, DEC witness D'Ascendis relied in his direct testimony on multiple analyses to arrive at his ROE recommendation. These analyses were a Constant Growth DCF Analysis, a Capital Asset Pricing Model analysis, an Empirical Capital Asset Pricing Model, a Bond Yield Plus Risk Premium analysis, and an Expected Earnings analysis. By way of comparison, Public Staff witness Woolridge and AGO witness Baudino relied upon DCF analyses and CAPM analyses in reaching their conclusions; however, the inputs utilized by these witnesses in their analyses are different from those utilized by witness D'Ascendis. CBD/AV witness McIlmoil recommended an ROE of 9.20% based on an ROE approved for Dominion Energy Virginia in a limited rider proceeding. Commercial Group witness Chriss recommended that the Commission look at the proposed ROE in light of recent ROEs approved by the Commission and by commissions nationwide. Similarly, CIGFUR witness Phillips looked at the average allowed ROEs for both vertically integrated and distribution-only electric utilities of 9.73% and recommended that average as a cap to the allowed ROE. CUCA witness O'Donnell proposed an ROE of 8.75% using the DCF and CAPM methodologies, as well as a comparable earnings approach. Finally, Tech Customers witness Strunk recommended a lower ROE in line with lower risk utilities but did not specify a percentage.

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[8] The revenue requirement impact of the Company's request prior to the stipulations and including the May 2020 Updates was actually a retail revenue increase of approximately $416 million; however, the Company limited its request to $414.5 million.

These varying analyses, as is typical, produced varying results. Witness D'Ascendis' analyses prompted him to propose an ROE range of 10.00% to 11.00% with a specific ROE recommendation of 10.50%. Witness Woolridge's analyses resulted in a recommended ROE range of 6.90% to 8.40% with a primary recommendation of a 9.00% ROE with a 50% common equity capital structure and a secondary recommendation of an 8.40% ROE if DEC's proposed capital structure of 47% long-term debt and 53% common equity was approved. AG witness Baudino proposed an ROE of 9.00%. Finally, as noted above, witness McIlmoil recommended an ROE of 9.20%, witness O'Donnell an ROE of 8.75%, and witness Phillips a cap on ROE of 9.73%.

The Commission finds the cost of equity analyses helpful in reaching its conclusion on an appropriate ROE for DEC but notes that the outputs of the various analyses included in direct testimony span a range from 5.00% to 11.10% and the specific ROE (primary) recommendations of the witnesses span a range from 8.75% on the low end to 10.50% on the high end.[9]

The Commission finds that the updated DCF, Bond Yield Risk Premium, and Expected Earnings analyses of DEC witness D'Ascendis, as well as the Second Partial Stipulation and the other intervenor settlements, are credible, probative evidence, and are entitled to substantial weight.

DEC witness D'Ascendis in his supplemental rebuttal testimony provided his Constant Growth DCF analyses, as shown on Supplemental Rebuttal Exhibit DWD-1, pages 1 and 2, as follows: 30-day dividend yield high ROE mean 9.67%, median 9.42%; and 90-day dividend yield high ROE mean 9.57%. The Commission finds witness D'Ascendis' Constant Growth DCF analyses mean and median ROE results credible, probative, and entitled to substantial weight.

DEC witness D'Ascendis' updated Bond Yield Plus Risk Premium, as shown on Supplemental Rebuttal Exhibit DWD-5, using the current 30-year Treasury yield of 1.47%, the near-term projected 30-year Treasury yield of 1.72%, and the long-term projected Treasury yield of 3.40% and applying it to the approved ROEs in 1,630 electric utility rate proceedings between January 1980 and June 30, 2020, results in ROEs of 10.25%, 10.08%, and 9.96%, respectively. While in the past, the Commission has generally approved the use of current interest rates rather than projected near-term or long-term interest rates, in this particular case, current market conditions give the Commission reason to look beyond the current Treasury yields and give some weight to projected rates. The Commission finds witness D'Ascendis' updated Bond Yield Plus Risk Premium analyses using the current and projected 30-year Treasury yields to be credible, probative, and entitled to substantial weight.

In this case, the Commission is concerned that the low ROEs recommended by CUCA witness O'Donnell, and to a lesser extent the ROEs recommended by AGO witness Baudino, and CBD/AV witness McIlmoil would, when translated into rates and

[9] As noted *infra*, DEC witness D'Ascendis recommended an ROE of 10.50%, but DEC requested a lower rate of return on equity of 10.30% to mitigate the impact of the rate increase on customers.

holding all other things equal, fail the *Hope* “end results” test. This is shown graphically in Chart 1 of D’Ascendis’ Rebuttal Testimony. Tr. vol. 11, 150. The Commission agrees with witness D’Ascendis that this could result in investors receiving a lower return with greater risk than would be available from other utilities, thereby making it more costly to raise capital. The Commission agrees with witness D’Ascendis that the ROE recommendations of witnesses Baudino, O’Donnell, and McIlmoil are unduly low, places great weight upon this observation, and therefore finds the Baudino, O’Donnell, and McIlmoil ROE recommendations to be unpersuasive. In doing so, the Commission emphasizes that it is referencing the data concerning other authorized ROEs as a means to test the ROE recommendations of witnesses Baudino, O’Donnell, and McIlmoil, and not as a reference to or reliance upon the doctrine of “gradualism.” *See Cooper II*, 367 N.C. at 443. *See also,* Order on Remand, *Application of Virginia Electric & Power Co., d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-22, Sub 479, at 33-35 (N.C.U.C. July 23, 2015).

Witnesses Baudino, O’Donnell, and McIlmoil recommended an ROE of 9.00%, 8.75%, and 9.20%, respectively. These recommendations are below the band of authorized ROE results set out in D’Ascendis’ Chart 1. These recommendations are also far below the stipulated 9.90% ROE from the Company’s previous rate case or 10.20% from the rate case prior to that. The recommendations of witnesses Baudino, O’Donnell, and McIlmoil are inconsistent with those recently authorized in North Carolina. The Commission has most recently authorized an ROE of 9.75% for Dominion Energy North Carolina; 9.90% for DEC and DEP in their prior rate cases, and 9.70% for Piedmont Natural Gas Company, Inc. Witness D’Ascendis indicated, and the Commission agrees, that these witnesses’ recommendations are far below the average and median ROE for vertically integrated electric utilities in jurisdictions rated in the top third by Regulatory Research Associates, which range from 9.37% to 10.55%. Witnesses Baudino, O’Donnell, and McIlmoil’s recommendations are below those of other vertically integrated utilities similarly rated from 2015–2020, while the settled ROE of 9.60% falls within that range.

In his direct testimony witness Baudino testified that his 9.00% ROE recommendation was “reasonably close to recently allowed ROEs”, using a 9.68% average ROE determination by commissions in 2017 as “recently allowed ROEs.” Witness Baudino admitted on cross-examination that he “would say [this 68-point differential] was reasonable.” Tr. vol. 2, 136. The differential between the stipulated ROE of 9.60% and witness Baudino’s 9.00% ROE recommendation is 60 basis points — less than the 68 basis points witness Baudino deemed “reasonable.”

There are other aspects of these witnesses’ analyses that the Commission finds lacking. For example, the Commission finds questionable witness Baudino’s failure to adjust his ROE recommendation in his supplemental direct testimony considering the recent volatility in the markets, increase in betas for the companies in the proxy group, and the higher DCF results in his supplemental testimony. Additionally, the Commission agrees with witness D’Ascendis’ criticism of witness Baudino’s growth rates applied to the Constant Growth DCF model and his reliance on the Constant Growth DCF model to determine the Company’s ROE, as well as the reasonableness of his Bond Yield Plus

Risk Premium analysis among other factors. Finally, the Commission also gives no weight to witness Baudino's CAPM approach as witness Baudino himself disregarded its unreasonably low results.

Regarding the ROE recommendation of CUCA witness O'Donnell, as with witness Baudino, his reliance on historical growth rates in the DCF analysis does not adequately encapsulate how the model is a forward-looking measure of investors' expectations. Further, the Commission finds compelling witness D'Ascendis' test of the relationship between retention ratios and future growth rates demonstrating that earnings growth actually decreased as the retention ratio increased, thereby undermining the premise underlying witness O'Donnell's use of the Retention Growth Model. As for witness O'Donnell's Comparable Earnings Approach, his updated forward-looking 2019 and 2022–2025 analysis yielding ROE estimates of 10.00% and 10.60% for his proxy group was similar to witness D'Ascendis' updated Expected Earnings analysis of 10.18% to 10.55%. Overall, it seems that witness O'Donnell's 8.75% ROE estimate is at odds with the data he presented.

Witness McIlmoil first proposed that the Commission use an ROE that the Virginia State Corporation Commission determined was appropriate for a Dominion Energy Virginia in a limited rider proceeding with a dead band. In his summary, witness McIlmoil lowered his recommended ROE to 9.00%, adopting the recommended ROE of another witness. The Commission declines to adopt this recommendation.

Additionally, witness D'Ascendis testified that the intervenor witnesses fail to recognize the risks faced by the Company and do not appropriately reflect the evolving capital market environment. Tr. vol. 11, 148. A significant departure from the authorized ROEs of other similarly situated utilities impacts the Company's ability to compete with other companies for long-term capital to provide safe and reliable utility service. The Commission notes the risk that an ROE in the range recommended by witnesses Baudino, O'Donnell, and McIlmoil could impact the Company's ability to compete for capital, as illustrated by witness D'Ascendis in his discussion of a recent rate decision in which the financial community responded negatively to an adverse regulatory outcome for CenterPoint Energy Houston Electric.

In sum, in light of all of the factors discussed in this Order, the Commission places minimal weight upon the ROE recommendations of witnesses O'Donnell, Baudino, and McIlmoil. Witness Strunk criticized the Company's ROE recommendation as excessive. In response, witness D'Ascendis noted in his second settlement testimony that the average authorized ROE for vertically integrated electric utilities from 2016 to June 2020 was 9.74%, 14 basis points above the stipulated ROE.

The Commission, of course, does not blindly follow ROE results allowed by other commissions. The Commission determines the appropriate ROE based upon the evidence and particular circumstances of each case. However, the Commission believes that the ROE trends and decisions by other regulatory authorities deserve some consideration, as (1) they provide a check or additional perspective on the case-specific circumstances, and (2) the Company must compete with other regulated utilities in the capital markets, meaning that an ROE significantly lower than that approved for other utilities of comparable risk would undermine the Company's ability to raise necessary capital, while an ROE significantly higher than other utilities of comparable risk would result in customers paying more than necessary. Both of those outcomes are undesirable and would result in unjust and unreasonable rates. The fact that the approved ROE falls 14 basis points below the average and within the range of recently approved ROE for other vertically integrated electric utilities lends support to the Commission's approval.

The record contains substantial evidence supporting the reasonableness of the stipulated ROE of 9.60%. The Commission notes generally that this ROE is well within the range of recommended returns by the economic experts in this docket of 8.75% to 10.50%. More specifically, an ROE of 9.60% falls within D'Ascendis' range under his constant growth DCF analyses and his Expected Earnings Analysis. Supplemental Rebuttal Ex. DWD-6. In prior cases, the Commission has given significant weight to the results of the Expected Earnings methodology, which stands separate and apart from the market-based methodologies (*e.g.,* the DCF or CAPM) also used by ROE experts. *See, e.g.*, 2013 DEP Rate Order at 36. The Commission chooses to do so again in this case. Moreover, 9.60% falls squarely within the range and very close to the average of recently allowed ROEs for vertically integrated electric utilities nationally. Lastly, the Commission notes that the stipulated ROE is 70 basis points lower than the ROE the Company requested in its Application. As such, the Commission concludes that 9.60%, is within the "zone of reasonableness" that leading commentators and the North Carolina Supreme Court have indicated is presumptively just and reasonable. *See State ex rel. Utils. Comm'n v. Gen. Tel. Co.*, 285 N.C. 671, 681, 208 S.E.2d 681, 688 (1974) (a "zone of reasonableness extending over a few hundredths of one per cent" exists within which the Commission may appropriately exercise its discretion in choosing a proper ROE).

As the Supreme Court made clear in *CUCA I* and *II*, the Commission should give full consideration to a nonunanimous stipulation itself, along with all evidence presented by other parties, in determining whether the stipulation's provisions should be accepted. *CUCA I*, 348 N.C. at 466, and *CUCA II*, 351 N.C. at 231, In this case, insofar as expert ROE testimony is concerned, both witnesses D'Ascendis and Woolridge support an ROE at 9.60%. Tr. vol. 11, 368 (D'Ascendis); tr. vol. 17, 225-26 (Woolridge). Only witnesses Baudino and McIlmoil questioned the settlement ROE, tr. vol. 2, 133; tr. vol. 10, 125, but, as indicated above, the Commission places very little weight upon their ROE recommendations. The Commission does note, however, that other intervenor settlements, as amended, support the use of an ROE of 9.60%. Thus, the Commission finds and concludes that the Second Partial Stipulation itself, along with the expert testimony of witnesses D'Ascendis and Woolridge, is credible evidence of the appropriate ROE and is entitled to substantial weight in the Commission's ultimate determination of this issue.

In summary, the Commission concludes that there is substantial evidence supporting the reasonableness of an ROE of 9.60%.

However, to meet its obligation as set forth in *Cooper I*, the Commission must address the impact of changing economic conditions on customers.

In this case, all parties had the opportunity to present the Commission with evidence concerning changing economic conditions as they affect customers. The testimony of witnesses D’Ascendis, Woolridge, and Baudino, which the Commission finds entitled to substantial weight, addresses changing economic conditions at some length. Witness D’Ascendis provided detailed data concerning changing economic conditions in North Carolina, as well as nationally, and concluded that the North Carolina-specific conditions are “highly correlated” with conditions in the broader nationwide economy. As such, witness D’Ascendis testified that changing economic conditions, both nationally and specific to North Carolina, are reflected in his ROE estimates.

Public Staff witness Woolridge agreed with DEC witness D’Ascendis that as of the time of the filing of his testimony, economic conditions had improved in North Carolina. He pointed out that at the time of the filing of his testimony, while the unemployment rates in North Carolina and DEC’s service territory had fallen by two-thirds since their peaks in the 2009-2010 period, they were both above the national average of 3.90%. Witness Woolridge also noted that while North Carolina’s residential electric rates are below the national average, its median household income is more than 10% below the U.S. norm.

However, subsequent to the filing of this case and as a result of the COVID-19 pandemic, economic conditions deteriorated in North Carolina and across the country during the first half of 2020. The Commission gives weight to the testimony of witness Baudino regarding the national decline of the GDP in the first quarter of 2020 by 5.0% as unemployment rose to 12.90% and 13.30% in May in North Carolina and the U.S., respectively. The Commission likewise gives weight to the testimony of witness D’Ascendis regarding the national and State unemployment rates in July of 10.2% and 8.5%, respectively, reflecting a quick rebound of at least some of the economic activity lost during the downturn.

As the Commission has noted, customer impact due to changing economic conditions is embedded in ROE expert witness analyses. Witness D’Ascendis’ analysis, which the Commission finds credible and to which the Commission gives weight, indicates that even though the North Carolina and U.S. economies have contracted, economic conditions in North Carolina continue to be highly correlated to conditions nationally, and, therefore, continue to be reflected in the analyses used to determine the allowed ROE. Witness D’Ascendis’ testimony regarding correlation between U.S. and North Carolina GDP growth for the fifteen years and four quarters ended March 2020, and employment in the US and DEC’s service territories from February to May 2020, demonstrate this point. The Commission also observes witness D’Ascendis’ testimony that North Carolina’s economy had been affected somewhat less severely than the national economy and its economic recovery had been somewhat more rapid.

Therefore, the Commission determines that the econometric data relied upon by ROE expert witnesses captures the effects and impacts of changing economic conditions upon customers.

Based upon the general state of the economy and the need for the continuing affordability of electric utility service, and after weighing and balancing factors affected by the changing economic conditions in making the subjective decisions required, the Commission concludes that the stipulated ROE of 9.60% will not cause undue hardship to customers, even though, the Commission acknowledges, some customers will struggle to pay for electric utility service.

Many of the adjustments to the Company's proposed rate increase reduce ratepayer responsibility and equity investor returns in compliance with the Commission's responsibility to establish rates as low as reasonably permissible without transgressing constitutional constraints, and thus, inure to the benefit of consumers' ability to pay their bills in this economic environment.[10] For example, to the extent the Commission made downward adjustments to rate base, disallowed test year expenses, increased test year revenues, or reduced the equity capital structure component, the Commission reduced the rates consumers will pay during the future period when rates will be in effect. In this case, the Commission has ordered negative adjustments to many expenses sought to be included in the Company's revenue requirement. Because the compensation owed to investors for investing in the Company's provision of service to consumers takes the form of return on investment, downward adjustments to rate base, disallowances of test year expenses, increases to test year revenues, or reduction in the equity capital structure component will reduce investors' return on investment irrespective of the determination of ROE.

The Commission has also approved herein an annual $2.5 million shareholder contribution to the Share the Warmth Fund in 2021 and 2022, as provided in the Second Partial Stipulation, and an annual contribution of $3 million, in conjunction with DEP, to the Helping Home Fund for two years, for a total contribution of $11 million of the Company's shareholder funds for energy assistance to low-income customers. NCSEA/NCJC et al. Stipulation, § IV. These decisions directly benefit customers with the least ability to pay in the current economic environment. The Commission takes these facts into account when approving the 9.60% ROE.

The Commission also recognizes that the Company is in a significant construction mode and much of the associated investment is for generation, transmission, and distribution infrastructure to benefit DEC's customers, as well as in response to recent increases in environmental compliance costs and other operating expenses. The need to invest significant sums to serve its customers requires the Company to maintain its creditworthiness in order to compete for large sums of capital on reasonable terms. The Commission must weigh the impact of changing economic conditions on DEC's customers against the benefits that those customers derive from the Company's ability to provide safe, adequate, and reliable electric service. Safe, adequate, and reliable electric service is essential to the well-being of the people, businesses, institutions, and economy

[10] The Commission notes that consumers pay "rates," a charge in cents per kilowatt-hour, for the electricity they consume. They do not pay a "rate of return on common equity," though it is a component of the Company's cost of providing service which is built into the charge per kilowatt-hour. Investors are compensated by earning a return on the capital they invest in the business. Per the Commission determination of the ROE in this matter, investors will have the opportunity to be paid in dollars for the dollars they invested at the rate of 9.60%.

of North Carolina. Thus, the Commission finds and concludes that such capital investments by the Company provide significant benefits to all of DEC's customers.

The Commission concludes in the exercise of its independent judgment and discretion that a 9.60% ROE is supported by the greater weight of the evidence and should be adopted. The hereby approved ROE appropriately balances the benefits received by DEC's customers from DEC's provision of safe, adequate, and reliable electric service in support of the well-being of the people, businesses, institutions, and economy of North Carolina (which benefits are symbiotically linked to the Company's ability to compete in the equity capital market to access capital on reasonable terms that will be fair to ratepayers) with the difficulties that some of DEC's customers will experience in paying DEC's adjusted rates. The Commission further concludes that a 9.60% ROE will allow DEC to compete in the market for equity capital, providing a fair return on investment to its investor-owners, and that the lowering of the rate from the requested 10.30% to 9.60% has the effect of lowering the cost of service which forms the basis of the rates the ratepayers must pay for service. Accordingly, the Commission concludes, taking into account changing economic conditions and their impact on customers, that the approved ROE will result in the lowest rates constitutionally permissible in this proceeding.

Finally, in approving the 9.60% ROE, the Commission gives significant weight to the stipulations and the benefits that they provide to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under the Supreme Court's holding in *CUCA I*.

As a result, the Commission concludes that the 9.60% stipulated ROE is reasonable and appropriate and is supported by the greater weight of the substantial evidence in the record.

B. Capital Structure

Summary of the Evidence

In DEC's Application witness Newlin proposed using a capital structure of 53% members' equity and 47% long-term debt. Tr. vol. 11, 381. Witness Newlin testified that the Company's "specific debt/equity ratio will vary over time, depending on a variety of factors, including among other things, the timing and size of capital investments and payments of large invoices, debt issuances, seasonality of earnings, and dividend payments to the parent company." *Id. at* 395-96. As of December 31, 2019, DEC's capital structure was 52% common equity and 48% long-term debt. Tr. vol. 17, 228.

In his direct testimony CUCA witness O'Donnell recommended that the Commission reject the Company's capital structure proposal and instead advocated a 50/50 structure. Witness O'Donnell's analysis supporting his 50/50 capital structure recommendation was based on his comparison of capital structures of publicly traded holding companies, not operating utility companies. Tr. vol. 20, 144.

Public Staff witness Woolridge testified that the Company's proposed capital structure included more common equity than the average of the proxy group he used in conducting his analysis. Tr. vol. 17, 110-11. He stated that it is appropriate to use the common equity ratios of the parent holding companies and that the high debt ratio and low equity ratio of DEC's parent company, Duke Energy, is credit negative for DEC as evaluated by Moody's. He noted, however, that because DEC is a regulated business, it is exposed to less business risk and can carry relatively more debt in its capital structure than most unregulated companies, like Duke Energy. *Id.* at 113-16. Witness Woolridge further testified that DEC should take advantage of its lower business risk to employ cheaper debt capital at a level that will benefit its customers through lower revenue requirements and, as a result, recommended a capital structure of 50% common equity and 50% debt based on a 9.00% ROE. Witness Woolridge also made an alternative capital structure recommendation of the Company's proposed structure of 47% long-term debt and 53% common equity based on an 8.40% ROE. *Id.* at 118-19.

AGO witness Baudino recommended that the Commission reject the Company's requested ratio and instead recommended the Commission approve the Company's December 2018 capital structure, which includes a common equity of 51.50%. Tr. vol. 16, 319, 382. As noted above, witness Baudino's recommendation is lower than the Company's recent actual capital structure of 52% equity and 48% long term debt.

Tech Customers witness Strunk concluded that the Company's proposed equity ratio is "above the mean and median equity ratio awarded" for other vertically integrated electric utilities across the country and therefore indicative of low financial risk. *Id.* at 141. Additionally, witness Strunk did not recommend a specific equity ratio, but did include in his proxy group 16 of 28 companies which have been authorized equity ratios above the 50% equity ratio recommended by witness O'Donnell. *Id.*

In his rebuttal testimony witness Newlin pointed out that CUCA witness O'Donnell utilized data showing capital structures that were inappropriate to use because they do not differentiate between various types of utility companies, which present different risk profiles. Tr. vol. 11, 403. Witness D'Ascendis testified that parent and operating companies do not necessarily have the same capital structures because financing at each level is driven by "the specific risks and funding requirements associated with their individual operations." Tr. vol. 11, 244. He noted the Commission's previous rejection of the use of parent company structures as opposed to operating company structures in determining the operating utility's appropriate equity/debt ratio. *See* Order Accepting Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application by Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-2, Sub 1142, at 87-88 (Feb. 23, 2018), *aff'd, in part, and remanded*, *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020) (2018 DEP Rate Order); Order Granting General Rate Increase and Approving Amended Stipulation, *Application of Duke Energy Carolinas, LLC, for an Increase in and Revisions to Its Rates and Charges Applicable to Electric Utility Service in North Carolina*, No. E-7, Sub 909, at 27-28 (Dec. 7, 2009) (2009 DEC Rate Order).

In addition, witness D'Ascendis noted the use of the operating subsidiary's actual capital structure — that is, the capital actually funding the utility operations that provide service to customers — is entirely consistent with precedent of the FERC so long as three criteria are met: the operating subsidiary (1) issues its own debt without guarantees, (2) has its own bond rating, and (3) has a capital structure within the range of capital structures for comparable utilities. *Id.* at 258-89. Witnesses Newlin and D'Ascendis testified that DEC, which issues its own debt and has its own bond rating, has a capital structure that is generally consistent with that of other operating companies, especially vertically integrated companies. *Id.* at 414-15 (Newlin); *id*. at 260 (D'Ascendis). Further, in response to witness O'Donnell, witness D'Ascendis testified that by excluding equity ratios authorized in jurisdictions that include non-investor supplied capital in the capital structure, witness O'Donnell's review demonstrated an average and median authorized equity ratio in 2019 of 51.93% and 52% for vertically integrated utilities. Tr. vol. 11, 325. Thus, he noted that the stipulated 52% equity ratio is consistent with authorized equity ratios. *Id.* DEC witness D'Ascendis also pointed out that witness Strunk, like witness O'Donnell, considers jurisdictions in which non-investor supplied capital is included in the capital structure, thus biasing his review. *Id.* at 334.

Subsequent to the filing of testimony, the Company reached several separate stipulations with the Public Staff, CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. agreeing that the rates in this proceeding should be set using a capital structure of 52% equity and 48% long-term debt. The 52% equity capital structure agreed to in the settlement agreements represents a compromise between the Company's 53% equity position and the intervenors' recommendations ranging from a 50% to a 51.50% equity capital structure.

Under Section III.B of the Second Partial Stipulation, DEC and the Public Staff proposed a capital structure of 52% common equity and 48% long-term debt. In their stipulation testimony Company witness Newlin and Public Staff witness Woolridge testified that the capital structure reflected in the Second Partial Stipulation represents a compromise by both parties in an effort to reach agreement and is in the public interest. Witness De May's second settlement testimony also supported the stipulated 52/48 capital structure. Tr. vol. 11, 888.

Discussion and Conclusions

In evaluating the evidence on capital structure in this proceeding the Commission first notes that the equity/debt ratios reflected in the Second Partial Stipulation and the stipulations with CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. of 52% equity and 48% long-term debt are consistent with and well within the prior decisions of the Commission.[11] That consistency is not a determinative factor from

[11] *See* DENC Docket No. E-22, Sub 532 Order (51.75% common equity and 48.25% debt); PSNC Sub 565 Order (52.0% common equity, 44.62% long-term debt, 3.38% short-term debt); PNG Sub 743 Order (52.00% equity, 47.15% long-term debt, 0.85% short-term debt); DEC Sub 1146 Order (52% common equity and 48% long-term debt); DEP Sub 1142 Order (52% common equity and 48% long-term debt); DENC Sub 562 Order (52% common equity and 48% long-term debt).

the Commission's perspective, but the prior decisions provide some context supporting the reasonableness of the stipulated capital structure.

Based upon its own review and independent analysis of the evidence, the Commission concludes that there is substantial evidence that a capital structure of 52% equity and 48% long-term debt, as is reflected in Section III.B. of the Second Partial Stipulation and the stipulations with CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. is just, reasonable, and appropriate on several grounds.

First, this capital structure is the same capital structure authorized for DEC in its last rate case. Second, this capital structure was accepted by the Public Staff, CIGFUR, the Commercial Group, Vote Solar, and Harris Teeter in separate stipulations. Third, the Commission gives great weight to Company witness Newlin's testimony that the stipulated capital structure is reasonable and appropriate when viewed in the context of the overall Second Partial Stipulation. Fourth, the Commission places great weight as well on witness Woolridge's conclusion that the end result of the settlement is fair and reasonable with respect to both ratepayers and shareholders, and that customers will benefit from lower rates as a result of a negotiated settlement. Fifth, the Commission also gives weight to the Second Partial Stipulation and the benefits that it provides to DEC's customers, which the Commission is obliged to consider as an independent piece of evidence under *CUCA I* and *II*. Each party to the Second Partial Stipulation gained some benefits that it deemed important and gave some concessions for those benefits. Based on the Application and prefiled testimony, it is apparent that the Second Partial Stipulation ties the 52% equity, 48% long-term debt capital structure to substantial concessions the Company made to reduce its revenue requirement. Sixth, the Commission gives weight to the Stipulations with CIGFUR, the Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. as it did to the Second Partial Stipulation.

Accordingly, based on the matters set forth above, and in the exercise of its independent judgment, the Commission finds that a preponderance of the evidence weighs in favor of the stipulated capital structure pursuant to Section III.B. of the Second Partial Stipulation and the stipulations with CIGFUR, Commercial Group, Harris Teeter, Vote Solar, NCSEA, and NCJC et al. and that such capital structure is just, reasonable, and appropriate for use in setting rates in this docket.

C. Cost of Debt

DEC witness Newlin testified that the Company's long-term debt cost as of December 31, 2018, was 4.51%, which was the value used to determine the revenue requirement in the Company's Application. As part of Section III.B of the Second Partial Stipulation, DEC and the Public Staff agreed to the May 2020 embedded cost of debt of 4.27%. The Commission finds for the reasons set forth herein that a 4.27% cost of debt is just and reasonable.

In his supplemental testimony Public Staff witness Woolridge initially proposed an updated cost of long-term debt (as of January 31, 2020) of 4.29%, and DEC updated its cost of debt to 4.29% in supplemental testimony filed July 6, 2020. Tr. vol. 17, 230. As part of the give-and-take negotiations involved in the settlement process, DEC and the Public Staff agreed to an updated cost of long-term debt (updated through May 2020) of 4.27%. *Id.*

No intervenor offered evidence to contradict the use of 4.27% as the cost of debt. The Commission therefore finds and concludes that the use of a debt cost of 4.27% per the terms of Section III.B of the Second Partial Stipulation is supported by the greater weight of the substantial evidence and is just and reasonable to all parties in light of all the evidence presented.

D. Credit Metrics

Summary of the Evidence

DEC Direct Testimony

Witness Newlin

DEC witness Newlin testified that his responsibilities as Senior Vice President, Corporate Development and Treasurer for Duke Energy include managing Duke Energy and its subsidiaries' credit ratings and interactions with major credit rating agencies. His testimony addressed DEC's financial objectives, capital structure, cost of capital, credit ratings, and forecasted capital needs. Witness Newlin emphasized the importance of DEC's continued ability to meet its financial objectives. He stated that the Company's proposed rate increase will allow it to recover prudently incurred costs, compete in the capital markets for needed capital, and preserve its financial standing with both debt and equity investors, as well as the credit rating agencies, to the long-term benefit of its customers. Consolidated Tr. Vol. 2, 376-79.

Witness Newlin testified that DEC has substantial capital needs over the next several years and that financial strength and access to capital at all times are necessary for DEC to provide service to its customers. To maintain its financial strength and flexibility, including its strong investment grade credit ratings, DEC has specific objectives including: (1) maintaining at least 53 percent common equity, (2) ensuring timely recovery of prudently incurred costs, (3) maintaining sufficient cash flows to meet obligations, and (4) maintaining a sufficient return on common equity to fairly compensate shareholders. *Id.* at 379.

Witness Newlin explained credit quality and credit ratings and how they are determined by the two major credit ratings agencies, Standard & Poor's (S&P) and Moody's Investor Service (Moody's). In assessing credit quality these agencies consider many qualitative and quantitative factors in assigning credit ratings. Qualitative factors may include DEC's regulatory climate, its track record for delivering on commitments, strength of management, its operating performance, and the economic vitality and customer profile of its service area. Quantitative measures are primarily based on operating cash flow and focus on the level at which DEC maintains financial leverage in relation to its generation of cash and its ability to meet its fixed obligations based on internally generated cash, such as its debt to capital ratio. Witness Newlin also provided the credit ratings by S&P and Moody's on DEC's outstanding debt, as of September 19, 2019, which show that DEC carries a credit rating compatible with strong, investment-grade securities, subject to low risk for an investor. *Id.* at 382-83.

However, according to his testimony, the ratings agencies have identified several challenges that DEC faces in maintaining its current credit ratings. These include downward pressure on credit metrics due to regulatory lag in the recovery of coal ash basin closure costs, reduced cash flows due to federal tax reform, and elevated capital expenditures. He elaborated that the Federal Tax Cut and Jobs Act of 2017 (Tax Act) resulted in electric utilities, including DEC, and their holding companies losing some of their cash flow from deferred taxes on an ongoing basis. He testified that this loss of cash flow would reduce DEC's funds from operations to debt ratio (FFO/Debt), a key credit metric. Because DEC's EDIT are customer-supplied funds, he testified that DEC proposes to flow the EDIT not subject to a statutory required flowback period over 20 years. In his opinion a 20-year period balances both the interest of customers and the financial strength of the Company and would smooth out the reduction in cash flow to DEC as it returns the EDIT to customers. *Id.* at 385-92.

Public Staff Direct Testimony

Witness Hinton

Public Staff witness Hinton testified to address concerns raised by Company witnesses Newlin and De May with regard to the credit metrics and the risk of a downgrade of DEC's credit ratings. He also testified in support of the Public Staff's recommended flowback of unprotected EDIT over a five-year period. Tr. vol. 17, 445.

Witness Hinton testified that DEC had provided the Public Staff with projected FFO/Debt credit metrics using both the five-year flowback period for unprotected EDIT recommended by the Public Staff and the 20-year flowback recommended by DEC. He noted that in Moody's October 31, 2019 Credit Opinion for DEC, an FFO/Debt metric that is between 24% to 26% qualifies for an "A" rating. He testified that the FFO/Debt metric would only be below 24% in 2021 with a five-year flowback. In his opinion, a temporary decrease in FFO/Debt would not likely lead to a downgrade of the Company's "Aa2" ratings on its first mortgage bonds or its "A1" senior unsecured bonds. Based on his analyses, he believes that unexpected financial developments would have to occur that reduced DEC's cash flow from operations or caused the Company to issue more debt to trigger a downgrade. In addition, he testified that Moody's and S&P place weight on factors other than credit metrics and that DEC has other means to finance the EDIT flowback over the five-year period, such as equity. Finally, witness Hinton testified that even if DEC's first mortgage bonds were downgraded by one notch to "Aa3," it is reasonable to expect that the investor-required bond yield would increase by five basis points under current market conditions and the downgrade would probably last less than five years. *Id.* at 445-52.

DEC Rebuttal Testimony

Witness Newlin

In rebuttal testimony DEC witness Newlin testified that he disagreed with Public Staff witness Hinton's advocacy for a five-year flowback of unprotected EDIT instead of the 20-year period proposed by the Company. He stated that reducing the Company's cash flow through a more accelerated flowback of unprotected EDIT at the same time that DEC is investing in large capital projects and refinancing obligations will negatively impact its credit metrics, which must be taken into account. Witness Newlin noted that in October 2018 Moody's, in its Credit Opinion of DEC, identified tax reform as one of the several factors that could adversely impact the Company's financial metrics (specifically, cash flow coverage ratios). Tr. vol. 11, 417-18.

Witness Newlin testified that it is reasonable that customers should benefit from the Tax Act and they will. However, he submitted that without the Commission's thoughtful consideration regarding all aspects of the Tax Act, particularly through a reduction in cash flow, the Company's credit quality could be adversely affected. He stated that an accelerated return of EDIT over an arbitrary five-year period would adversely impact the Company's cash flow and FFO/Debt ratio. Furthermore, witness Hinton's analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other credit-negative proposals by the Public Staff including a lower return on equity, a more leveraged capital structure, disallowance of a return on coal ash costs, and other recommendations for ratemaking that would reduce cash flows and increase debt. *Id.* at 420-22.

Witness Newlin also testified that witness Hinton's estimate of a five-basis point increase in debt cost as a result of a downgrade is based on capital market conditions reflecting historically low interest rates and near record tight credit spreads. He testified that credit spreads can widen significantly during periods of uncertainty and market volatility. With regard to witness Hinton's estimate that a downgrade could last only five years, witness Newlin stated that five years is a long time, and such a presumption is overly optimistic. Witness Newlin noted that Moody's mentions a downgrade would occur if FFO/Debt is below 25% on a sustained basis. However, witness Newlin testified that an upgrade would require significantly higher metrics and would require approximately $300 million in incremental annual cash flows on a sustained basis with no additional leverage to achieve a 30% FFO/Debt ratio, which would likely require significant rate increases over prolonged periods. *Id.* at 423-25.

Witness Young

DEC witness Young, Executive Vice President and Chief Financial Officer for Duke Energy, testified in rebuttal on the financial needs of Duke Energy investors, the impact of utility regulation on the Company's credit profile and investors, the benefits to customers of having a financially healthy utility, the Company's concerns with some of the proposals offered by intervenors in this proceeding (and with the Commission's recent Dominion Energy North Carolina Order issued in Docket No. E-22, Sub 562), and the reasons those proposals should not be adopted by the Commission in this proceeding. Tr. vol. 11, 441.

Witness Young testified that neither Duke Energy nor DEC has access to any established “reserves” to pay the carrying costs of unavoidable debt (and supply equity) needed to support utility operations. He testified that having to simply absorb those carrying costs could have significant negative implications to the financial stability of the enterprise as a whole. Witness Young explained that energy utility operations are often cash flow negative due to the need to serve a growing customer base, repair and maintain existing infrastructure, and immediately respond to all service interruptions such as those caused by major storms. Duke Energy’s ability to fund these investments is based upon investor confidence that customer rates will be set at levels that allow all prudent utility operating and financing costs to be recovered. *Id.* at 448.

Witness Fetter

DEC rebuttal witness Fetter, a consultant of DEC, testified mainly in response to the Public Staff’s recommendation for an equitable 50/50 sharing of CCR compliance costs. Utilizing his past experience as a state utility commission chairman and head of the utility rating practice at Fitch, Inc., he discussed how the adoption of such a recommendation would be inappropriate and viewed negatively by the credit rating agencies and investors. Tr. vol. 26, 88.

Witness Fetter testified that DEC corporate issuer credit ratings span between the highest level (A1, Stable outlook at Moody’s) and the lowest level (A-, Stable outlook at S&P) of the “A” category. He testified that a regulated utility should endeavor to hold no lower than Baa1 (Moody’s) to BBB+ (S&P), with a longer-term goal of moving into or maintaining the A category. *Id.* at 67.

Witness Fetter testified that the most qualitative factors used by rating agencies are regulation, management, and business strategy, along with access to energy, gas and fuel supply with timely recovery of associated costs. He testified that credit rating agencies look for the consistent application of sound economic and regulatory principles by utility regulators. *Id.* at 68, 70.

Witness Fetter testified that the financial community’s view of the Commission has been relatively positive. He testified that Regulatory Research Associates (RRA) currently rates the North Carolina regulatory environment, which goes beyond the Commission to also include legislative and executive branch policies, as Average 1, among the top one-third of the 53 regulatory jurisdictions currently rated by RRA. He testified that RRA’s view of North Carolina’s regulation as overall relatively constructive from an investor viewpoint serves as a positive factor in the credit rating analytical process. *Id.* at 74.

Witness Fetter testified that Moody’s cautions that a DEC credit downgrade could occur if there is a decline in the credit supportiveness of DEC’s regulatory relationships, particularly with regards to coal ash remediation recovery in North Carolina. *Id. at* 75. He stated that the Public Staff’s sharing recommendation undercuts both the quantitative and qualitative factors that are positives in the credit rating agencies' assessment of DEC's ratings. The equitable 50/50 sharing proposal, in his opinion, is inconsistent with the core regulatory principle that prudently incurred costs should be allowed for recovery in customer rates. He testified that this principle is fundamental to the regulatory compact that undergirds investor willingness to provide needed funding to public utilities in exchange for a fair return or investment. Based upon his background he believes that a stark movement away from traditional ratemaking principals, which would also be a clear break away from past Commission precedent, would shake the perception of investors and increase the costs of both equity and debt capital, an impact that ultimately lands at the doorstep of the customer. Accordingly, he recommended that the Company should seek to achieve excellent operating performance going forward and that the Commission should sustain the ongoing constructive regulatory environment, which together should maintain the Company's credit ratings no lower than their current levels within the "A" category. *Id. at* 379-80.

Discussion and Conclusions

The Commission notes that the parties submitted a considerable amount of testimony explaining credit metrics, quality, and ratings. The Company, in particular, shared its views on the potential impact of the Commission's decisions on several issues in this proceeding with regard to possible future credit ratings changes and investor perceptions. The Commission found such testimony to be informative and appreciates the efforts of the parties in this regard.

The Commission recognizes and acknowledges that its decisions on important issues in general rate cases are part of the regulatory climate of a public utility operating within North Carolina and are critically reviewed by credit rating agencies. So too are the statutory framework and appellate court decisions. Ultimately, utility management is responsible for managing credit metrics and ratings and investor perceptions. It is they who have levers, such as timing and selection of future capital project spending, issuances of securities and dividend policy, managing daily operations efficiently, and even the provision of a convincing evidentiary record when prudency issues are raised in a proceeding such as this one.

North Carolina General Statutes Section 62-133 sets forth the factors to be considered by the Commission in setting rates for public utilities, stating:

> In fixing rates for any public utility subject to the provisions of this Chapter, . . . the Commission shall fix such rates as shall be fair to both the public utilities and to the consumer.

N.C.G.S. § 62-133(a). The statute further provides that "[t]he Commission shall consider all other material facts of record that will enable it to determine what are reasonable and just rates." N.C.G.S. § 62-133(d).

The statute does not require that the Commission consider the utility's credit ratings or stock prices when fixing rates, a fact that was conceded by DEC witnesses.

However, the Commission must set rates that are reasonable and fair to both its customers and existing investors and should allow the utility to compete in the capital markets on reasonable terms.

The Commission has decided the issues in this proceeding based upon the requirements of N.C.G.S. § 62-133. The Commission has given the evidence on credit metrics due consideration. The rates fixed by this Order are supported by the greater weight of the evidence, are fair to both the public utilities and customers, produce just and reasonable rates, and should allow the utility, through prudent management, to access the capital markets on reasonable terms. Indeed, as to the last point the Commission views the ROE and capital structure approved herein to be investor and credit supportive.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 36

Cost of Service Adjustments

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of DEC witnesses McManeus, Metzler, Speros, Hatcher, Pirro, Kuznar, and Hager, Public Staff witnesses Boswell, Saillor, Metz, McLawhorn, and Maness, and CBD/AV witness Ryan; and the entire record in this proceeding.

Summary of the Evidence

As previously discussed, DEC and the Public Staff reached partial settlements with respect to many of the revenue requirement issues presented by the Company's Application, including those arising from the supplemental and rebuttal testimonies and exhibits. Section III of the First Partial Stipulation outlines a number of accounting adjustments to which DEC and the Public Staff have agreed, as does Section III.J. of the Second Partial Stipulation. The accounting adjustments that are not specifically addressed in other findings and conclusions are discussed in more detail below.

Executive Compensation and Incentive Compensation

In its Application the Company removed 50% of the compensation of the five Duke Energy executives with the highest level of compensation allocated to DEC in the test period. Witness McManeus explained that while the Company believes these costs are reasonable, prudent, and appropriate to recover from customers, DEC has for purposes of this case made an adjustment to this item. Tr. vol. 11, 476. Public Staff witness Boswell recommended an additional adjustment to remove 50% of the benefits associated with these top five Duke Energy executives. Tr. vol. 17, 248-49. She contended that this adjustment is consistent with the positions taken by the Public Staff and approved by the Commission in past general rate cases involving investor-owned electric utilities serving North Carolina retail customers and that it is appropriate and reasonable for the shareholders of the larger electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests. *Id.* at 249-50. Witness Boswell also recommended disallowance of incentive compensation related to

EPS and total shareholder return (TSR). *Id.* at 251-52. She asserted that incentive compensation tied to EPS and TSR metrics should be excluded because it provides a direct benefit to shareholders only, rather than to customers. *Id.* at 252.

In her rebuttal testimony Company witness Metzler testified that the Public Staff's proposed adjustments are inappropriate and should be rejected by the Commission. Tr. vol. 11, 807. According to witness Metzler employee compensation and incentives tied to metrics such as EPS and TSR benefit customers because those metrics reflect how employees' contributions translate into overall financial performance. *Id.* at 814.

Additionally, witness Metzler explained that in order to attract a well-qualified and well-led workforce the Company must compete in the marketplace to obtain the services of these employees. Finally, witness Metzler pointed out that no witness in this proceeding challenged the reasonableness of the level of compensation expenses reflected in the test period. *Id.* at 815.

The First Partial Stipulation provides that "[t]he Company accepts the Public Staff's proposed adjustment to executive compensation to remove 50% of the benefits associated with the five Duke Energy executives with the highest amounts of compensation, in addition to the 50% of their compensation removed in the Company's initial Application." First Partial Stipulation, § III.7.

As part of First Partial Stipulation DEC and the Public Staff agreed to accept the Public Staff's adjustment with a modification to limit the incentives removed. This agreement is reflected in Section III.10 of the First Partial Stipulation, which provides that the Company's employee incentives should be adjusted to remove incentive pay related to EPS and TSR for the top levels of Company leadership.

Rate Case Expenses

In its Application the Company requested to amortize the incremental rate case costs incurred for this docket over a five-year period. Tr. vol. 11, 480. The Public Staff made an adjustment to remove the unamortized portion of rate case expense in rate base, reasoning that the amortization of rate case expense should reflect a normalization of the costs associated with the filing of a rate case, based on a historical average of the number of years between rate case filings. Tr. vol. 17, 259. Public Staff witness Boswell testified that that rate case expense does not rise to the level of being extraordinary in nature and therefore does not require rate base treatment. *Id.* In her rebuttal testimony witness McManeus testified that the Company opposed the Public Staff's adjustment and contended that if the Public Staff had used the historical average costs and number of years between rate case filings since 2013, the amortization amount would have been $1.5 million, which is higher than the Company's proposed amortization amount. Tr. vol. 11, 525. Because the costs are known and measurable, the Company argues that inclusion of the costs in rate base is appropriate because they are incremental costs that have been incurred and funded by investors prior to new rates becoming effective. *Id.* However, in the spirit of settlement, DEC and the Public Staff agreed to amortize the rate case expenses over a five-year period with the unamortized balance not included in rate base. First Partial Stipulation, § III.8.

Aviation Expenses

In its initial filing as updated by its February 14, 2020 supplemental filing, DEC removed 50% of the corporate aviation costs to account for flights that may not be related to provision of electric service. Tr. vol. 11, 480. The Public Staff made a further adjustment after investigating the aviation expenses charged to DEC during the test year. Tr. vol. 17, 252. Public Staff witness Boswell contended that based on her review of the flight logs, some of the flights appeared to be unrelated to the provision of utility services, and in other instances the costs of flights had been incorrectly allocated. *Id.* at 253. The Public Staff also removed the DEC-allocated portion of commercial international flights due to the Public Staff's determination that those flights were unrelated to the provision of utility service. *Id.*

In rebuttal Company witness McManeus explained that all of the costs of the corporate aircraft have been allocated in accordance with the Company's cost allocation manual and that the Company's proposal to remove 50% of the costs is consistent with the Commission's order in Sub 1142. Tr. vol. 11, 524. She also pointed out that the Public Staff's recommendation would result in recovery of less than 2% of corporate aviation costs. *Id.* For the purposes of settlement, the parties agreed to an adjustment that removes aviation expenses associated with international flights, in addition to the 50% of the Company's corporate aviation O&M expense removed in the Company's initial application. First Partial Stipulation, § III.9.

Sponsorships and Donations

Public Staff witness Boswell adjusted the Company's O&M expenses to remove amounts paid to the chambers of commerce, the North Carolina Chamber, and other donations, reasoning that they should be disallowed because they do not represent actual costs of providing electric service. Tr. vol. 17, 260. CBD/AV witness Ryan also recommended that Chamber of Commerce dues be disallowed. *Id.* at 489. In his rebuttal testimony Company witness Speros testified that Chambers of Commerce promote business and economic development, which in turn helps to retain and attract customers to DEC's service territory. Tr. vol. 15, 114. He explained that funds paid to Chambers of Commerce that are not specified as a donation or lobbying on the Chamber invoice are supporting business or economic development and are considered to be properly charged as a utility operating expense that should be included in the Company's cost of providing electric service to customers. *Id.* Nevertheless, as part of the First Partial Stipulation the Company agreed to accept the Public Staff's position on sponsorships and donations expense, and it removed amounts paid to the U.S. Chamber of Commerce and certain other expenses. First Partial Stipulation, § III.11.

Severance Costs

The Company made an adjustment to remove atypical severance and retention costs included in the test period and also requested to establish a regulatory asset to defer the North Carolina retail amount of $69.1 million of severance costs beginning when rates go in effect, to be amortized over a three-year period. Tr. vol. 17, 260-61. Public Staff witness Boswell adjusted the severance costs to reflect a normalized level over a three-year period, consistent with how the Public Staff has treated severance program costs in other utility rate cases. *Id.* at 261. In its rebuttal testimony the Company opposed the Public Staff's adjustment arguing that the adjustment only changed the proposed amortization period and did not calculate a normalized five-year level of severance expense, which would have been greater than the Company's proposed amortization amount. Tr. vol. 11, 525-26. Nevertheless, in the spirit of settlement, DEC and the Public Staff agreed that the severance expenses should be amortized over a three-year period, but the unamortized balance will not be included in rate base. First Partial Stipulation, § III.12.

Lobbying Expenses

With respect to lobbying expenses Public Staff witness Boswell noted that the Company assigned some lobbying expenses from the test year to below-the-line accounts and therefore that those costs were not included in the cost of service. Tr. vol. 17, 254. She further adjusted O&M expenses to remove what she characterized as additional lobbying costs, including O&M expenses that she believed were associated with stakeholder engagement, state government affairs, and federal affairs that were recorded above the line. *Id.* In his rebuttal testimony DEC witness Speros explained why the Company opposed this adjustment and disagreed with witness Boswell's characterization of these expenses. Tr. vol. 15, 108. Witness Speros testified that the amounts the Company has booked above the line align with an independent study performed by KPMG. *Id.*

In the spirit of settlement and in the context of the First Partial Stipulation as a whole, the Company and the Public Staff reached settlement on the lobbying expenses, and the Company agreed to accept the Public Staff's recommended adjustments to lobbying expenses. First Partial Stipulation, § III.13.

CBD/AV witness Ryan recommended that the Commission disallow recovery of costs related to DEC's support of Edison Electric Institute (EEI), Nuclear Energy Institute (NEI), Institute of Nuclear Power Operations (INPO), Utility Water Act Group (UWAG), and all Chambers of Commerce. Tr. vol. 17, 487-89. She contended that under the First Amendment of the U.S. Constitution individuals may not be compelled to provide financial support to entities that engage in political activities, regardless of how the funds are used, and that DEC has not demonstrated that the funds are not being used to support lobbying or other political activities. *Id.* at 489. Witness Speros disagreed with witness Ryan's recommended disallowance and explained that the Company already books any costs for these organizations that is related to lobbying, political activities, or contributions to a charitable foundation below the line. Tr. vol. 15, 112. According to witness Speros, these organizations are required to clearly identify the portion of dues that relate to these types of activities, and DEC automatically excludes these amounts from cost of service, as demonstrated in the Company's responses to data requests in this case. *Id.* at 112-13, 116. Moreover, he stated that the Public Staff conducted a full and complete audit of the Company's expenses and did not identify any improper amounts relating to dues paid to industry organizations like EEI, NEI, INPO, and UWAG. With respect to the portion of such dues that are recorded above the line, witness Speros testified that it is not reasonable to assume that all of these 34 organizations' activities constitute lobbying, or that because the organizations engage in some lobbying and political activities their other activities have no benefit to customers. *Id.* at 113. He explained that all of these entities are electric industry trade organizations that provide valuable resources to their member utilities such as training and testing for members' employees; information relating to cybersecurity initiatives, energy efficiency programs, and customer solutions; access to industry data; and breaking news on topics such as preparing for the coronavirus. *Id.* He concluded that customers benefit from the Company's participation in industry organizations as it keeps DEC current on industry trends, developments, innovative programs, and emerging safety issues, among other things. *Id.* at 113-14.

Board of Director Expenses

Witness Boswell made an adjustment to remove 50% of the expenses associated with the Board of Directors of Duke Energy that have been allocated to DEC. Tr. vol. 17, 250. Witness Boswell argued that the premise of this adjustment is closely linked to the premise of the adjustment the Public Staff made related to executive compensation in that the Board of Directors has a fiduciary duty to protect the interests of shareholders which may differ from the interests of ratepayers. *Id.* The Public Staff noted that it is appropriate for the shareholders of the larger electric utilities to bear a reasonable share of the costs of compensating the Board of Directors, as well as the cost of insurance for these individuals which has been utilized to defend the Board of Directors in suits brought by shareholders. *Id.* Witness Metzler explained that the Company is required to have a Board of Directors and that the costs of being an investor-owned utility, including Board costs, are in fact costs of service. Tr. vol. 11, 817. She argued that it is not fair or reasonable to penalize the Company for being an investor-owned utility with attendant requirements to that corporate structure. *Id.* As part of the First Partial Stipulation, the Company agreed to accept the Public Staff's recommended adjustments to the Board of Directors' expenses. First Partial Stipulation, § III.13.

Retired Hydro O&M Expenses

In May and December of 2018, the Company retired several hydro units at Rocky Creek, Great Falls, and 99 Islands. Tr. vol. 17, 260. Public Staff witness Boswell included an adjustment to remove all non-payroll related O&M costs related to these retired hydro units. *Id.* In her rebuttal testimony Company witness McManeus testified that the Company did not oppose this adjustment, and as part of the First Partial Stipulation the Company accepted the Public Staff's adjustment. Tr. vol. 11, 521; First Partial Stipulation, § III.13.

Credit Card Fees

In its Application DEC requests approval of a fee-free payment program for credit, debit, and ACH payment methods used by the Company's residential customers to pay their electric bills. Application at 11. Currently, customers are required to pay a $1.50 convenience fee, collected by a third-party vendor, for payments made by a credit card. To offer a fee-free payment program the Company proposes to pay these costs on behalf of its residential customers and recover the costs as part of its cost of service. Company witness McManeus described in her direct testimony the Company's proposal to adjust its O&M expense to adjust for credit card fee expenses, and she made an adjustment to reflect actual numbers of credit card transactions through January 2020. Tr. vol. 11, 482, 508.

Company witness Hatcher testified to the value and need for the customer-driven program. Tr. vol. 11, 921-22. Witness Hatcher explained that the requirement to pay a convenience fee when making a payment is one of the largest frustrations the Company's residential customers experience. He stated that the Company's Customer Service department routinely receives inquiries about no-cost electronic payment options as evidenced by the Company's monthly residential transaction surveys. According to witness Hatcher, customers have grown accustomed to paying for other products and services with a credit card or debit card without a separate, additional fee, and as customer expectations change and more payments are done electronically, utility companies are now offering fee-free payment programs for their residential customers for all methods of payment. Accordingly, witness Hatcher believes DEC residential customers will appreciate being able to use these payment methods with the Company the same way they can with other companies. As stated by witness Hatcher, Duke Energy has seen 14% average year over year growth in credit/debit transactions over the past several years, and with this change the Company expects the growth rate to double — so 28% more transactions in 2019 than in 2018. *Id.* at 921-23.

While no party contested the value or benefits of the fee-free credit card program for residential customers, Public Staff witness Boswell noted that the Company did not calculate any impacts to late payments or uncollectibles associated with the request to include credit card fees and has not removed the expenses related to the forms of payment that were utilized in the 2018 cost of service. Therefore, the Public Staff made an adjustment to remove the O&M expenses included in the cost of service for 2018 associated with the increase in credit card transactions from the 2018 to 2019 period, to avoid double-counting costs associated with the same payments. In addition, the Public Staff recommends the Company track the impact of the credit cards that no longer have a separate fee associated with the payment, on the late payment and uncollectible accounts, and report the quantitative impact in testimony in the Company's next general rate case. Tr. vol. 17, 255-56. In her rebuttal testimony Company witness McManeus testified that the Company partially agreed with the Public Staff's adjustment and accepted the concept of the Public Staff's adjustment to remove O&M expense associated with the increase in fee-free program transactions from 2018 to 2019. Tr. vol. 11, 520. However, witness McManeus testified that the Company has updated the calculation to reflect avoided transaction costs related to payment by check as reflected in McManeus Rebuttal Exhibit 1. *Id.* In his rebuttal testimony witness Hatcher testified that no party has contested the fee-free program. *Id.* at 928. In addition, in response to witness Boswell's recommendation that the Company track the impact of the fee-free program on the late payment and uncollectible accounts, he explained that the Company does not track the payment method with the customer's delinquency status at the time the payment is received. Instead, the Company blends all costs incurred for bill payment-related expenses, which is reflected in the cost of service; thus, any quantitative impact would be reflected in the future cost of service. Instead, the Company proposed to track and report the number of payments made by channel per year in the next general rate case. *Id.* As part of the First Partial Stipulation, the Public Staff agrees to the Company's rebuttal position on credit card fees. First Partial Stipulation, § III.14.

Advertising Expenses

Public Staff witness Boswell adjusted O&M expenses to exclude (1) items incorrectly booked to advertising, (2) advertising amounts for which the Company could not provide support, and (3) image and promotional advertising, consistent with prior Commission orders. Tr. vol. 17, 256. DEC witness Speros testified that regarding the first category where the costs were incorrectly booked to advertising, the costs were related to painting power poles, were inadvertently booked to the wrong FERC account, and are being corrected. Tr. vol. 15, 115. However, the Company opposed witness Boswell's adjustment because although the costs were booked to the wrong FERC account, the Company's position is that the costs are reasonable and prudent expenditures that should be recoverable in retail rates. *Id.* In her rebuttal testimony DEC witness McManeus testified that the Company does not oppose the remaining categories of advertising expense adjustments proposed by the Public Staff. Tr. vol. 11, 521. As part of the First Partial Stipulation, the Public Staff agreed to the Company's rebuttal position on advertising expenses. First Partial Stipulation, § III.14.

May 2020 Updates

On July 2, 2020, the Company filed second supplemental direct testimony and exhibits updating certain material pro forma adjustments through May 31, 2020 (May 2020 Updates). The Company updated revenue requirements through May 2020 for the following pro forma adjustments: customer growth, post-test year additions to plant in service, accumulated depreciation, depreciation expense, property taxes, O&M nonlabor expenses, O&M labor expenses, merger related costs, interest synchronization, cash working capital, and an adjustment to update and remove storm costs for securitization. Tr. vol. 11, 575-76. Though the Public Staff initially opposed the May 2020 Updates, DEC and the Public Staff eventually reached agreement regarding the consideration of the updates in the Second Partial Stipulation and agreed to include the adjustments, pending and subject to the Public Staff's audit of the updates. Second Partial Stipulation, §§ III.J, IV.A. DEC and the Public Staff also agreed to include updates for benefits and executive compensation. *Id.,* § III.J. Finally, DEC and the Public Staff agreed to limit the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's January 2020 update to recognize the uncertainty regarding the effects of COVID-19, and the 75% limitation is applicable only if the net effect of the updates on revenues is a revenue requirement increase. *Id.*

After completing the aforementioned audit, on September 8, 2020, Public Staff witness Boswell filed second supplemental and settlement testimony and exhibits updating and revising the Public Staff's calculation of its recommended revenue requirement, including the impacts of the Second Partial Stipulation and the accompanying review of the Company's May 2020 Updates. The Public Staff reviewed the Company's proposed updates to net plant, depreciation expense and accumulated depreciation, new depreciation rates, and revenues and related expenses (weather, and customer growth and usage). The Public Staff recommended certain adjustments to these items, and also recommended an adjustment to update certain employee benefits, weather, and customer growth and usage, which adjustments were reflected in Boswell Second Supplemental and Stipulation Exhibit 1. Tr. vol. 22, 76-77. The adjustments for benefits, weather, and customer growth and usage totaled $953,000, exclusive of the impact on cash working capital.

Lead-Lag Study

The Company submitted a new Lead-Lag Study as Speros Exhibit 3. DEC subsequently revised Speros Exhibit 3 as part of the supplemental testimony of DEC witness Speros. In her direct testimony Public Staff witness Boswell proposed adjustments to cash working capital based on the Public Staff's review of the Lead-Lag Study. Witness Speros testified that the Company agreed with the Public Staff's adjustments to cash working capital and noted that the adjustments are consistent with the changes he described in his supplemental testimony that are included in the revised Lead-Lag Study. Tr. vol. 15, 107.

Weather Normalization, Customer Growth and Usage

DEC witness Pirro testified that he provided the retail sales and number of customers to DEC witness McManeus for use in calculating the pro forma adjustment to growth in customers. Tr. vol. 12, 237. He explained that to arrive at the appropriate number of customers served and the attendant annualized sales levels at the end of the test period, the Company used a combination of regression analysis and a customer-by-customer approach. *Id.* In his supplemental direct testimony witness Pirro testified that the Company had adjusted customer growth to reflect actual customer growth data and weather impacts through January 2020. He also testified that the adjustment to normalize for weather had been updated to incorporate additional months of actual sales and weather data through January 2020, and the average cents/kWh for the residential class has been revised to remove the Basic Facilities Charge (BFC) component. *Id.* at 258-59.

Public Staff witness Saillor proposed modifications to the Company's customer growth, weather normalization, and change in usage adjustments. Tr. vol. 16, 640. In terms of weather normalization, witness Saillor testified that monthly kWh adjustments are determined to weather normalize test period sales for the residential, general, and industrial rate classes. He explained that the revenue adjustment is calculated by multiplying the total rate class kWh adjustment by the average customer class rates based on annualized revenues divided by per book sales. He recommended that the revenues generated from per-bill basic facilities charges be removed because the weather effect does not change the number of bills rendered during the test period. He also summed the monthly North Carolina retail kWh weather adjustments updated through November 2019, as provided to the Public Staff by DEC, for each month of the test period for each customer class. He explained that each monthly adjustment is based on the monthly system weather adjustment and each month's North Carolina sales to system sales ratio. This is in place of the method used in the Form E-1, Item 10 worksheet NC-0301 where the North Carolina retail kWh weather adjustment per class is calculated by multiplying the test period system kWh weather adjustment times the annual North Carolina retail to system sales ratio. Witness Saillor explained that he believes that summing the monthly North Carolinas retail kWh adjustments more accurately reflects the normal weather adjustment being represented by DEC. *Id.* at 641-45.

To annualize revenues for customer growth and change in usage witness Saillor proposed modifications to the methodology proposed by DEC. *Id.* at 647. He revised DEC's customer-by-customer approach for calculating the average monthly usage for each new general and industrial customer added to the system during the test period by summing the 12 months of billing data following the initial month of service and dividing that value by 12, which he believes results in a more precise representation of the customer's average monthly usage. Witness Saillor further revised the customer-by-customer approach by removing the initial month of service from the average usage calculation for new general and industrial customers added to the system after the end of the test period. For change in usage calculations, witness Saillor removed the BFC revenues reasoning that the increase or decrease in usage would not change the number of bills included in annualized revenue. For the lighting rate class, witness Saillor removed the change in usage revenue adjustment under the rationale that lighting accounts are billed on a per-light basis, and revenues for the lighting class would not change due to changes in usage. Witness Saillor also calculated a change in usage adjustment for the general and industrial rate classes based on the difference in the monthly average weather-normalized usage per customer. *Id.* at 647-49.

In his supplemental testimony Public Staff witness Saillor testified that the Company agreed with his proposed modifications for weather, customer growth, and change in usage. Witness Saillor explained that he made one change to DEC's method for updating the change in the number of test period bills for the general and industrial rate classes by instead finding the difference between the number of bills added to the test period for new accounts and the number of bills removed from the test period for closed accounts from DEC's customer-by-customer approach for calculating customer growth. *Id.* at 653.

As part of the First Partial Stipulation the Company agreed to accept the Public Staff's updated recommended adjustments to weather normalization, growth and usage as reflected in Boswell Supplemental and Stipulation Exhibit 1. First Partial Stipulation, § III.15. Subsequently, in his second supplemental direct testimony witness Pirro testified that the Company updated its customer growth adjustment through May 31, 2020, to incorporate certain known and measurable changes. He explained that the updated customer growth adjustment reflects a significant reduction in the Company's load and associated revenues as a result of many commercial and industrial customers and schools and colleges scaling back operations, as well as an increase in residential usage, during the COVID-19 pandemic. Tr. vol. 12, 273-74). In support of the updated customer growth adjustment witness Pirro testified that reflecting these changes closer in time to the rescheduled hearing will result in a more accurate depiction of the Company's load forecast and customer usage. *Id.* at 274. As noted above, DEC and the Public Staff eventually reached agreement regarding the May 2020 Updates and agreed to include the adjustments, pending and subject to the Public Staff's audit of the updates, and also subject to a limit of the updates on revenues to 75% of the difference between the May 2020 Updates and the Company's January 2020 update to recognize the uncertainty regarding the effects of COVID-19 if the net effect of the updates on revenues is a revenue requirement increase. Witness Pirro filed Pirro Second Settlement Exhibit 4 to reflect the revised revenue requirement resulting from the Second Partial Stipulation and the Company's position on unsettled items.

Non-Labor O&M

The Company adjusted annual non-labor, non-fuel O&M costs to reflect the increase in costs during the test year that occurred due to the effect of inflation as of December 31, 2018. Public Staff witness Boswell adjusted the Company's inflation adjustment to reflect the Public Staff's adjustment to include variable O&M expenses for changes in customer growth and the removal of aviation expenses, Board of Directors expenses, outside services expenses, uncollectibles, sponsorships and donations, and advertising. In rebuttal testimony Company witness McManeus did not oppose the adjustment. Subsequently, in the Second Partial Stipulation the Public Staff and the Company agreed to the allocation methodology to apply to the expenses, as well as to reflect the inflation factor through May 31, 2020, to coordinate with other items updated through that same point in time. The specific updated Public Staff adjustments discussed in witness Boswell's testimony to which the Company agrees are as follows.

Plant in Service and Accumulated Depreciation

Public Staff witness Boswell updated net plant for known and actual changes to depreciation expense and non-generation plant retirements recorded between the end of the test year and May 31, 2020. Witness Boswell also included adjustments recommended by Public Staff witness Metz removing costs related to the Lincoln CT Plant and the Company's Project Focal Point. The impact of the removal of costs associated with the Lincoln CT Plant and Project Focal Point, which were each part of the Public Staff's adjustments to the update of plant, depreciation expense, and accumulated depreciation, are included in the unsettled update to plant and accumulated depreciation as of May 31, 2020, listed on Schedule 1, Line 6 of Boswell Second Supplemental and Stipulation Exhibit 1. Although the Public Staff and the Company agree the items should be removed from plant in service and accumulated depreciation, the item remains unsettled until the Commission determines the appropriate depreciation rates, which are included in the calculation of the adjustment. The Company agreed that these adjustments should be included in the calculation of the final revenue requirement determined in the present case.

Updated Revenues

Public Staff witness Boswell updated the energy-related non-fuel variable O&M expense per kWh rate and the annual customer-related variable O&M expense per kWh rate to reflect the calculations to include amounts determined pursuant to the SCP allocation methodology. Furthermore, witness Boswell included the fuel factors recently approved by the Commission in Docket No. E-7, Sub 1228 in the calculation of annualized revenues and fuel expense, including growth, usage, and weather normalization impacts. The Company agreed with this adjustment. *Id.* at 81.

Benefits

Public Staff witness Boswell updated the benefits related to OPEB, pension, FASB 112, and non-qualified pensions to reflect the updated 2020 actuarial amounts that became available after the January 31, 2020 update period. The Company agreed with this adjustment. *Id.* at 81-82.

Clemson CHP

In his supplemental testimony Public Staff witness Metz recommended that capital costs in the amount of $50.3 million associated with the Company's Clemson CHP Project be removed from rate base. Tr. vol. 16, 680, 684. Witness Metz discussed the mechanics of combined heat and power (CHP) technology and described his understanding of the location, size, and purpose of the CHP Project as providing thermal energy (steam) service for the Clemson University (University) campus pursuant to a contract between the Company and the University (Steam Agreement). *Id.* at 681-83. He asserted that the per kW cost of approximately $4,800 for the CHP Project was extraordinarily high as compared to combined cycle (CC) plants and to combustion turbine (CT) costs used in the Company's avoided cost calculations *Id.* at 684. He also expressed concerns with other provisions of the Steam Agreement and questioned the need for the project. *Id.* at 685-709. Public Staff witness Boswell in her supplemental and settlement testimony incorporated an adjustment to remove the CHP Project from plant in service and made corresponding adjustments to depreciation expense and accumulated depreciation based on witness Metz's recommendation. Tr. vol. 17, 279.

In his rebuttal testimony Company witness Kuznar described CHP systems, including their efficiency and environmental benefits. He discussed the Company's overall strategy of exploring CHP as an option to diversify its regulated generation mix with distributed, smaller assets that can economically meet future customer demand as well as reduce transmission and distribution losses and improve reliability. Tr. vol. 11, 827-28. Witness Kuznar also clarified that the North Carolina retail share of the CHP Project was $33.9 million. *Id.* at 833. Witness Kuznar testified that the Public Staff's recommended disallowance disregarded the benefits that North Carolina customers will receive from the

Company's investment in the CHP Project. *Id.* at 826, 831. He also disagreed with witness Metz that the cost for the CHP Project was too high. *Id.* at 834-35.

In her supplemental rebuttal testimony witness Hager testified that the Public Staff's position that the costs of the CHP Project should not be allocated to North Carolina retail customers because, in part, the electricity may never reach DEC's transmission system is inconsistent with sound cost allocation principles. Witness Hager explained that physical location does not govern whether a generation resource is a system asset: if a generation resource is available to serve system load requirements, it is a system asset and is generally allocated to all jurisdictions across the system. Tr. vol. 12, 225.

Section III.K of the Second Partial Stipulation provides that "[t]he Company accepts the Public Staff's recommended system disallowance of $19.1 million for the Clemson Combined Heat and Power Project."

Company witness McManeus, tr. vol. 11, 582, Public Staff witness Boswell, tr. vol. 17, 284-86, and Public Staff witness McLawhorn, tr. vol. 18, 255, supported the provision for the disallowance for the CHP Project through their testimony in support of the Second Partial Stipulation. Witness Boswell presented the final $10 million adjustment to North Carolina retail in her Second Supplemental and Stipulation Exhibit 1, Schedule 2-1(g). Tr. vol. 22, 77-78.

Deferred Non-ARO Environmental Costs

Public Staff witness Maness testified that pursuant to the Commission's approval of the 2016 request for deferral filed in Docket No. E-7, Sub 1110, the Company is proposing to defer and amortize certain depreciation and return requirements related to certain capital projects placed into plant in service since its most recent rate proceeding. Tr. vol. 20, 519. He explained that these projects are not classified by the Company as legal obligations associated with the retirement of coal ash facilities or the generating plants with which those facilities are associated; instead, they are intended to address coal ash issues related to the continuing operation of the applicable generating plants. Although they are not part of the legal obligation that gives rise to DEC's coal ash ARO, the Company and Public Staff agree that these costs are eligible for deferral pursuant to the terms of the Sub 1110 deferral accounting request, because they are needed to fulfill the Company's responsibilities under CAMA and the EPA's CCR Rule. However, witness Maness testified that although he does not oppose deferral of the capital (return and depreciation) costs of the projects in this case, he does not agree with the five-year period proposed by the Company over which to amortize the deferred costs. He instead recommends an amortization period of ten years, which would lower the revenue requirement and substantially ease the annual impact of the deferral and amortization on the ratepayer, noting that the reduction would not directly harm the Company in that the unamortized amount would earn a return through being included in rate base. *Id.* at 519-22.

In rebuttal DEC witness McManeus testified that the Company does not agree with witness Maness's recommendation to increase the amortization period for non-ARO related deferred capital expenditures. Tr. vol. 11, 540. She explained that the Company considered annual rate impacts in its recommendation of the five-year amortization and considered the Commission's decision in the 2018 DEC Rate Order in arriving at its proposed amortization period. *Id.* Nevertheless, in the spirit of settlement DEC and the Public Staff have agreed to amortize deferred non-ARO environmental costs over an eight-year period. Second Partial Stipulation, § III.L.

Discussion and Conclusions

Based on the foregoing and the record, the Commission concludes that the provisions of the Public Staff First and Second Partial Stipulations on cost-of-service adjustments aptly demonstrate the efforts of the stipulating parties to reach compromise on many details of DEC's operating costs. Auditing a public utility's accounting records and formulating a position on the many cost of service items is a labor intensive and tedious job. The Commission appreciates the work of the Public Staff and the stipulating parties for coming together and working out many of these accounting issues. The Commission determines that the cost adjustment provisions are the result of give-and-take negotiations, and therefore the Commission places great weight on the cost adjustment provisions of Public Staff stipulations. As a result, the Commission concludes that the stipulated adjustments discussed herein are just and reasonable, and the portions of the Public Staff First and Second Stipulations on cost-of-service adjustments should be approved.

With regard to the issue of lobbying expenses raised by CBD/AV, the Commission agrees that organizations such as EEI, NEI, INPO, and UWAG engage in non-lobbying and non-political activities that benefit customers, and the Commission finds that DEC's practice of excluding the portions of dues paid to trade groups that relate to lobbying or political activities is consistent with the Commission's guidance on this issue. In addition, the Commission gives significant weight to the fact that the Public Staff found no reason to disallow the portions of dues paid by the Company to EEI, NEI, INPO, and UWAG included in the Company's cost of service.

Further, in its Order Dismissing Petition in Part, Granting Petition to Intervene, Joining Necessary Parties, and Requesting Comments in Docket No. M-100, Sub 150 issued on August 29, 2019 (Lobbying Rulemaking Order), the Commission rejected the constitutional arguments asserted by CBD/AV. Lobbying Rulemaking Order at 3-6. Further, the Commission stated :

> The utilities' memberships in trade groups such as EEI and EPRI for research, development of best business practices, and other educational purposes can be well worth the dues paid, both for the utilities and their ratepayers. But the cost of lobbying activities by such organizations, for legislative advocacy often on a national level that may have little or nothing to do with North Carolina's public interest, is not a cost that should be borne by North Carolina's ratepayers.

> Therefore, the Commission finds good cause to request comments on the following proposed additional definition to Rule R12-12, and the underlined additions to Rules R1212(d) and R12-13(a).

Id. at 14-15.

The Lobbying Rulemaking Order set forth extensive proposed definitions and potential restrictions on lobbying costs and charitable contributions, among others. As noted, the Commission invited comments on these proposed guidelines. In response, the Commission has received extensive comments. The Commission is weighing the comments, statutes, rules of other jurisdictions, and other factors that bear on the recovery of costs associated with lobbying, trade organization membership, and similar activities and will issue its findings and decision on that issue in that proceeding.

Lastly, the Commission finds and concludes that the adjustment to the Company's revenue requirement of $19.1 million on a system basis for the CHP Project as reflected in the Second Partial Stipulation and in witness Boswell's Second Supplemental and Stipulation Exhibit 1, Schedule 2-1(g), reflects a compromise among the parties in this proceeding, and the Commission finds that compromise reasonable and appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 37–41

Deferral of Grid Improvement Plan Capital Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations entered into between DEC and several parties; the testimony and exhibits of DEC witnesses McManeus, Young, and Oliver, Public Staff witnesses David Williamson, Tommy Williamson, Maness, Thomas, and McLawhorn, NCSEA/NCJC et al. witnesses Stephens and Alvarez, CIGFUR witness Phillips, CUCA witness O'Donnell, Harris Teeter witness Bieber, NC WARN witness Powers, Tech Customers witness Strunk, and Vote Solar witnesses Nostrand and Fitch; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Jane McManeus explained that the Company requests an accounting order that would allow DEC to defer its GIP capital costs starting with costs incurred in January 2020. She asserted that DEC's GIP costs meet the Commission's test for deferral because they are not simple, regularly occurring, inconsequential investments but rather are major nonroutine investments that produce substantial customer benefits. She testified that absent deferral, if DEC pursued its proposed GIP spending, the Company would experience a significant adverse earnings impact that would grow to over 100 basis points by 2022.

DEC witness Steven Young testified that investors are looking for modernized mechanisms that allow more timely recovery of investments. He stated that "now most of our investments are smaller in nature. They go in service quicker." He stated that the Company must absorb the related depreciation, O&M and interest expense, and the deferral mechanism helps to address the lag in both cash and in earnings. Tr. vol. 3, 49-50.

DEC witness Jay Oliver testified that DEC had developed its GIP to respond to these seven "megatrends":

(1) Population and business growth continue in North Carolina and is concentrated in urban and suburban areas.
(2) Distributed energy technology is advancing rapidly; there are new kinds of load and resources impacting the grid.
(3) New technologies offer new capabilities and functions for the grid.
(4) Customer expectations have changed.
(5) There are more environmental commitments at every level of government.
(6) Major weather events are more numerous and more severe.
(7) Physical and cyber threats to the grid are more sophisticated and are increasing.

Witness Oliver stated that DEC seeks deferral accounting for $1.3 billion in spending on the following GIP programs during 2020 through 2022: (1) Self-Optimizing Grid (SOG), (2) Integrated Volt/VAR Control (IVVC), (3) Transmission Hardening and Resiliency, (4) Targeted Undergrounding, (5)Distribution Transformer Retrofit, (6) Long Duration Interruptions/High Impact Sites, (7) Transmission Transformer Bank Replacement, (8) Oil Breaker Replacements, (9) Enterprise Communications, (10) Distribution Automation, (11) Transmission System Intelligence, (12) Enterprise Applications, (13) Integrated System Operations Planning (ISOP), (14) Distributed Energy Resource (DER) Dispatch Enterprise Tool, (15) Power Electronics for Volt/VAR Control, and (16) Physical and Cyber Security.

Public Staff Direct Testimony

Public Staff witnesses David Williamson and Tommy Williamson testified that DEC is currently working on 12 of the GIP programs and that it had spent about $52 million on the programs during the 2018 test year on a system basis, and another $273 million in 2019, again on a system basis. The Public Staff reviewed DEC's proposed GIP to identify programs that are unique and extraordinary and hence appropriate to consider for deferral. They sought to identify those programs that would bring the grid up to new standards of operation and reliability. The Public Staff rejected for deferral those programs that are the kinds of activities that DEC engages in or should engage in on a routine and continuous basis. The Public Staff concluded that the following GIP programs are extraordinary: (1) the automation and control portion of the SOG, (2) the advanced distribution management system portion of the SOG, (3) IVVC, (4) Transmission System Intelligence, (5) the Underground System Automation portion of Distribution Automation, and (6) ISOP. The Public Staff believes these initiatives are transformative and would provide significant new capabilities to the grid.

Public Staff witness Maness testified that DEC intends to spend about $445 million on the GIP programs that witnesses Williamsons identified as being extraordinary. He stated that absent deferral, the return on equity impact of these programs would average 20.33 basis points over the three years, and under normal circumstances the Public Staff would not recommend deferral of an investment with a basis point impact that is so small. He stated that in this case, however, the Public Staff took notice of the Commission's order from DEC's last rate case, Sub 1146. Witness Maness asserted that in the 2018 DEC Rate Order the Commission appeared willing to be lenient regarding the magnitude of costs or financial impacts necessary to justify deferral for grid improvement investments. For that reason he did not object to the Commission allowing deferral of the capital costs of the six programs identified by witnesses Williamsons, as long as the Commission determined that the estimated basis point impact falls within the range of leniency that the Commission is willing to grant. Witness Maness further stated that such a deferral should be considered specific to this case and not precedential with regard to any future general rate case proceeding or deferral request.

Public Staff witness Thomas reviewed the cost-benefit analyses that DEC provided for some of the GIP programs. While he did not recommend rejection of any of the programs, he did express concern that a majority of the benefits identified in DEC's cost-benefit analyses were estimates of the financial benefits customers would receive by avoiding power outages. He testified that DEC relied on a Lawrence Berkeley National Laboratory (LBNL) report to estimate the financial value of these benefits. Witness Thomas testified that 87% of the benefits of DEC's GIP were customer reliability benefits, and about 97% of those benefits would accrue to commercial and industrial customers. Witness Thomas testified that DEC's cost estimates for the GIP programs were of a high-level nature, and actual costs could vary widely from such estimates. He pointed out other concerns with DEC's cost-benefit analyses but ultimately did not recommend rejection of any of them. He recommended that GIP expenditures should be tracked and reported, that DEC should perform cost-benefit analyses for additional GIP programs, that DEC should file sensitivity analyses of its cost-benefit analyses that include cost variations, that DEC should consider conducting a study to more accurately reflect its customers' outage costs, and that DEC should remove or modify benefits in its analyses, including long-term reliability benefits, CO_2 emission savings, avoided capacity planning margin requirements gross-up, and avoided capacity in years when no capacity is needed. In addition, Thomas recommended that DEC revise its analysis for the Transmission Hardening and Resiliency program to assign reliability benefits to customer classes. He stated that DEC should revise the SOG cost-benefit analysis to include the effect of momentary outages and the expected reduction in vegetation-related outages from increased vegetation management. Thomas said DEC should consider how GIP investments would impact other costs, such as inventories, and that DEC and the Commission should consider changing the allocation of GIP costs among customer classes.

Public Staff witness McLawhorn stated that the benefits derived from some of the GIP transmission and distribution assets are disproportionally related to the way the GIP transmission and distribution plant is allocated. He believes this area of cost allocation deserves further study.

NCJC et al. Direct Testimony

Witness Stephens reviewed DEC's GIP, including its cost-benefit analyses. He identified deficiencies in some and a lack of justification for others. He recommended that the Commission reject DEC's GIP and establish a separate proceeding for developing a new GIP plan and budget. He identified eight of DEC's GIP programs that merit approval, with conditions, because they represent standard industry practice; they consist of software that is needed to optimize grid assets, operations, or cyber security; they are likely to deliver benefits to ratepayers in excess of costs; or they are critical to provide stakeholders' value that cannot be otherwise secured. These eight programs are: (1) IVVC; (2) the flood and animal mitigation portions of Transmission Hardening and Restoration; (3) Long Duration Interruptions/High Impact Sites; (4) foundational software including Enterprise Applications, ISOP, and DER Dispatch; (5) Cyber Security (excluding substation physical security); (6) Enterprise Communications (excluding mission critical voice and data network); (7) Power Electronics for Volt/VAR Control; and (8) Automated Distribution Management System.

Witness Stephens stated that the SOG program should be approved but at a reduced level to focus on circuits that would experience the greatest benefit. As to the Transmission Hardening and Resiliency program, he stated that the entire budget should focus on projects to accommodate more distributed energy resources.

Witness Stephens testified that the Commission should reject the following programs because they are not generally cost-effective: (1) Targeted Undergrounding, (2) Distribution Transformer Retrofits, (3) Transformer Bank Replacements, (4) Oil-filled Breaker Replacements, and (5) Substation Physical Security. Witness Stephens recommended that the Commission require on-going performance measurement for DEC's GIP initiatives as well as cost caps and operating audits.

In addition, witness Stephens recommended that the Commission reject the Mission Critical Voice and Data Network Development programs because DEC completed no make-versus-buy evaluation of alternatives to its own $160 million proposal to build proprietary voice and data networks. Similarly, Stephens said DEC provided no cost-benefit analyses for its Distribution Automation and Transmission System Intelligence programs.

Witness Paul Alvarez criticized DEC's reliance on the LBNL report for estimating outage costs; he said the report is based on old data that is geographically biased and biased toward manufacturing and retail businesses that have the highest outage costs of all commercial and industrial (C&I) segments. Further, the surveys used to collect outage cost data did not consistently address the availability of back-up generators and uninterruptible power supply systems. Witness Alvarez asserted that DEC over-estimated the GIP's benefits by overstating the number of outages being avoided by the programs, then by overstating the economic benefits of those avoided outages, and finally by using those overstated primary benefits as inputs to the IMPLAN software, which estimates the secondary benefit. Further, he contended that DEC did not estimate the detrimental impacts on North Carolina's economy of the significant rate increases that the GIP would generate. He asserted that the GIP would cause a 4.1% rate increase, that residential customers would likely be allocated about 48% of the costs, and that they would pay at least $7.85 for every $1 in benefits that the receive. On the other hand, he asserted that DEC's shareholders would likely earn $2.6 billion in return on equity over 30 years, or $1.2 billion in present value terms, from its GIP investments. He testified that DEC's GIP will ultimately cost ratepayers $8.7 billion over 30 years, or $3.5 billion in present value terms. He also asserted that the GIP presents an asymmetrical risk profile, one in which ratepayers take all the risk for benefit delivery and cost overruns, while shareholders earn a rate of return under all scenarios. He recommended that the Commission reject DEC's GIP and its request for deferral accounting and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process.

CBD/AV Direct Testimony

Witness Wolf advocated for the presentation of all costs and benefits in DEC's GIP analyses; transparency of regionally appropriate distributed energy resources and opportunities for them to interconnect; increased customer access to their usage data and sources of energy; facilitation of greater use of storage, demand-side resources, grid operation/management devices, and bi-directional flow of power; performance measurement to ensure benefits are delivered; and increased deployment of renewable energy.

Witness Ryan recommended that the Commission reject DEC's request for deferral of GIP costs until after the 2020 IRP proceeding. She stated that DEC failed to explain how its GIP programs address the identified megatrends and that DEC did not disclose how burdensome its GIP expenditures would be for ratepayers.

CIGFUR Direct Testimony

Witness Phillips testified that there is no compelling evidence demonstrating that grid improvements warrant a departure from standard ratemaking practices. Further, he asserted that DEC's plan would shift regulatory risk from its investors to customers as well as allow DEC to pursue single-issue ratemaking. He testified that the deferral, if approved, could eliminate DEC's incentive to prudently manage costs between rate cases, and GIP costs are not volatile or unpredictable. Witness Phillips stated that if the deferral is approved, DEC's allowed ROE should be reduced to reflect the reduced business risk that its investors will face.

CUCA Direct Testimony

Witness O'Donnell testified that DEC's proposed grid expenditures are too expensive and lack customer support. He stated that many of the programs lack cost-benefit analyses to prove that they are beneficial and should therefore be disallowed. He stated that the Commission should only allow recovery of GIP programs costs where promised reliability benefits are achieved.

Witness O'Donnell testified that regulated utilities have an incentive to build plant, and that DEC offered no performance guarantees. He asserted that DEC intends to pursue its Power Forward grid initiative, of which GIP is a part, and that this $13 billion ten-year grid modernization effort will cause massive rate increases. He asserted that a typical industrial customer would pay $12 million more over ten years due to DEC's GIP investments.

Harris Teeter Direct Testimony

Witness Bieber recommended that the Commission reject DEC's proposal to defer GIP costs. He stated that deferral is unnecessary and would amount to single-issue ratemaking. Witness Bieber testified that DEC's GIP costs do not appear to be volatile or outside the Company's control, and they should be considered in the context of general rate cases.

NC WARN Direct Testimony

Witness Powers recommended that the Commission reject DEC's GIP proposal, stating that the stakeholder workshops that DEC hosted were essentially sales presentations. He stated that the high cost of the GIP is such that additional rigorous review is needed to protect ratepayers. He testified that the GIP presumes that there is only one pathway to grid modernization and that other alternatives should be considered. For example, installing battery storage in residences would be a less costly way to improve reliability than the Targeted Undergrounding program that DEC proposes.

Tech Customers Direct Testimony

Witness Strunk testified that DEC has not justified the use of deferral accounting for its GIP and failed to justify treating those investments differently from other infrastructure investments. He stated that DEC used speculative, indirect benefits to legitimize its GIP expenditures. Witness Strunk testified that DEC's GIP is premature and should await the results of its ISOP planning process.

Witness Strunk testified that the two-pronged test used by the Commission to determine whether to approve deferral requests is the correct approach. He stated that the Commission should consider whether the costs in question are unusual or extraordinary and whether, absent deferral, the costs would have a material impact on the utility's financial condition. He said that DEC did not prove its case that the deferral request meets either of the prongs. He said there is overlap between DEC's regular transmission and distribution spending and the GIP, and DEC did not explain how it would differentiate between what costs are to be deferred and what costs are not.

Witness Strunk testified that the megatrends driving DEC's GIP are not likely temporary, and they are nothing new. He described them as systemic influencers that are the opposite of unusual and extraordinary.

Witness Strunk responded to DEC witness McManeus' testimony about the financial impact of the deferral, the testimony in which she said that absent the deferral DEC's earnings degradation would grow to more than 100 basis points by 2022. Witness Strunk stated that this assertion is flawed in two ways. First, it assumes that DEC would invest the same amount over the same time frame if GIP deferral were denied. He testified that this is contradicted by witness Oliver, who suggested that DEC would spend less on GIP without the deferral. In addition, witness Strunk said that witness McManeus' analysis looks at the GIP investments in isolation, without considering how other elements of DEC's spending and balance sheet will evolve. According to witness Strunk, witness McManeus' analysis failed to consider the natural reduction in rate base that DEC's asset portfolio experiences over time due to depreciation.

Witness Strunk criticized DEC's GIP cost-benefit analyses because DEC did not incorporate customer preferences for lower electric rates. Similarly, DEC did not consider the negative effects on the economy of raising electric rates. He stated that the $7 billion of indirect benefits that DEC ascribed to its GIP appear to be speculative.

Vote Solar Direct Testimony

Witnesses Nostrand and Fitch testified that DEC's GIP does not assess or respond to climate-related risks, and it does not adhere to grid modernization best practices. They recommended that the Commission: (1) direct DEC to assess and manage climate-related risks across its operations and assets, (2) make clear that it will apply this standard to GIP investments, (3) direct DEC to participate in DEQ stakeholder processes around grid modernization, and integrate data, findings, and recommendations into its GIP, (4) require DEC to file a report identifying gaps in knowledge that need to be filled through further collaboration, (5) require DEC to develop a GIP through an integrated distribution planning process, and (6) if GIP deferral is allowed, impose performance-based conditions on the recovery of the deferred amounts.

DEC Rebuttal Testimony

Witness Oliver stated that none of the intervenor witnesses credibly disputed the megatrends that are driving the need for the GIP. Tr. vol. 11, 641.

As to the Public Staff's assertion that some GIP programs do not meet the definition of grid modernization, witness Oliver argued that each program within the GIP seeks to bring the current grid up to new standards of operation or reliability. He then used the same matrix and methodology for analyzing GIP programs that the Public Staff had developed, scored the programs higher for some attributes, and concluded that these programs should be added to the Public Staff's list of "extraordinary" programs:

(1) SOG Capacity and Connectivity;
(2) Transmission Hardening and Resiliency – 44-kV System Upgrade Subprogram;
(3) Distribution Automation (the Underground System Automation subprogram was already included in the Public Staff's list);
(4) Power Electronics;

(5) Distributed Energy Resource Dispatch Tool; and
(6) Cyber Security.

Where the Public Staff's list of six "extraordinary" programs totals $492 million in capital spending from 2020-2022, witness Oliver's six programs would add $433 million to that amount, for a total of $925 million. As to the other programs, witness Oliver stated that the Public Staff's evaluation method is one rational approach, but it is not the only way to evaluate programs. Witness Oliver asserted that all of DEC's GIP initiatives meet the definition of grid modernization, and all of their costs should be eligible for deferral.

The most expensive GIP program that the Public Staff disputed is SOG at $420 million in capital over three years. Witness Oliver stated that SOG is an example of a GIP project that addresses all of the megatrends, not just reliability. He said that when wide-spread, privately owned roof-top solar is adopted, a dynamic, automated, capacity-enabled two-way power flow grid is an essential component to be in place. During lightly loaded shoulder seasons SOG would allow excess DER energy to be routed to adjacent neighborhoods for use, maximizing its value and reducing line losses.

Witness Oliver asserted that SOG will allow DEC to defer capacity. He stated further that DEC plans to deploy SOG on circuits where it will have the most benefit. Since that deployment will increase DEC's efficiency when responding to outages, it will benefit all customers. Witness Oliver disagreed with Public Staff witness Thomas's assertion that SOG will result in an increased number of momentary outages.

Witness Oliver responded to witness Thomas's concern that SOG benefits are overstated because DEC failed to consider the reduced number of vegetation-related outages that will occur due to DEC's tree trimming plans. Witness Oliver stated that DEC's increased tree trimming would reduce SOG benefits by only about 2%. In addition, DEC's cost-benefit analysis for SOG did not include any benefits for improving reliability on major event days. He said that SOG is a "no regrets" investment that provides significant value for customers in multiple ways.

As to the 44-kV System Upgrade program, witness Oliver stated that this effort would protect the 44-kV system from extreme weather and begin to pave the way for more DER interconnections. Witness Oliver responded to witness Alvarez's assertion that DEC's GIP cost-benefit analyses contain $425 million in capital spending that is not included in DEC's three-year capital spending. Witness Oliver stated that it is not accurate to compare the capital budget spending plan in his Exhibit 10 to the costs in DEC's cost-benefit analyses because they serve different purposes. He stated that some of the cost-benefit analyses are for projects or programs that start in the 2020–2022 period but continue into 2023 and beyond.

Oliver stated that the majority of the $1.1 billion in software and communications replacement costs identified by witness Alvarez are justified under cost-effective guidelines instead of via a cost-benefit analysis. He said that there is no need to evaluate all programs over the same lifecycle.

As to witness Alvarez's assertions that DEC did not consider alternatives for its $160 million in communications network investments, witness Oliver said DEC followed documented enterprise supply chain processes, including requests for information and requests for proposals, to evaluate alternatives. He said that, where appropriate, considering the cost, security, speed to deploy and level of service required, external carriers provide services to DEC's networks. He testified that core data network requirements exceed the current capabilities that third-party cellular providers can provide given their bandwidth limitations. Witness Oliver stated that for the Land Mobile Radio program, alternative services were considered, and bidders were eliminated because of their inability to meet requirements.

Witness Oliver disagreed with witness Alvarez's assertion that DEC's cost-benefit analyses overstate benefits to C&I customers, calling this assertion misleading. As to witness Alvarez's critique of DEC's IMPLAN analysis, witness Oliver stated that the impact of rate increases was outside the scope of that analysis.

Witness Oliver asserted that the cost-benefit analyses included in his direct testimony provide metrics for the programs, such as the amount of O&M savings DEC anticipates, the amount of avoided capital costs DEC anticipates, and the number of outages each program is anticipated to avoid. He said that DEC will track project/program scope, schedule, cost and benefits as appropriate during implementation.

In response to witnesses who argued that DEC's transformer retrofit, bank replacements, breaker replacements, and transmission line rebuilds were not appropriate grid modernization initiatives and that they are business-as-usual activities, witness Oliver stated that the GIP accelerates the pace of these efforts to better position DEC to deal with the future requirements.

As to DEC's Targeted Undergrounding program, witness Oliver acknowledged that its scope had been scaled back by about 90%. He said the remaining program is highly cost beneficial. He disagreed with witnesses who asserted that Targeted Undergrounding is not standard industry practice and that both Dominion Energy in Virginia and Florida Power & Light in Florida have similar programs.

As to DEC's plans to upgrade the security of substations, witness Oliver stated that DEC used a graded approach to physical security at substations not covered by NERC CIP-014, NERC's physical security standard. Witness Oliver stated that most substations will not need security improvements.

In response to critics of Duke's grid modernization stakeholder process, witness Oliver stated that DEC used the feedback received in the workshops to validate the megatrends, conduct additional analyses, drive future workshop discussions, and make significant changes to the portfolio of investments.

He stated that the GIP is a three-year plan, while Power Forward was a ten-year plan, and that the scope of the two plans is dramatically different. He noted that Distribution Hardening and Resiliency and Targeted Undergrounding made up 64% of

Power Forward but are only 11% percent of the three-year GIP, and also that GIP contains several new programs, specifically IVVC at 10% percent of the total, and Physical and Cyber Security at 6%. He stated that SOG is generally supported by all stakeholders; it made up less than 10% of Power Forward but is the largest program in the three-year GIP, making up over 31% of the total. Witness Oliver stated further that the GIP begins to prepare the North Carolina grid for growth in privately owned DER and electric vehicles, but even if this growth does not occur, the plan still is cost-effective. He stated further that there is currently no "Phase 2" of the plan, and any future plan would be based on collaboration with stakeholders.

Witness Oliver acknowledged that the GIP does not address third-party owned DER accommodation in North Carolina. He stated that while some GIP programs and projects provide ancillary benefits to interconnection issues, those benefits are secondary to their primary purposes.

Witness Oliver recommended that the Commission ignore witness Alvarez's recommendation to reject the GIP and establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. Witness Oliver referred to Exhibit 3 of his direct testimony, which lists six negative implications of a business-as-usual response to DEC's identified megatrends:

(1) Increased costs;
(2) Reduced reliability and resiliency;
(3) Reduced ability to manage and integrate distributed energy resources;
(4) Reduced ability to meet customer expectations and commitments;
(5) Reduced economic competitiveness for North Carolina; and
(6) Increased geographic and demographic disparity.

Witness Oliver stated that if the Commission were to reject the Company's deferral request, the work in the GIP would have to be sub-optimized, delayed, diminished in scope and effectiveness, and potentially not done at all.

Similarly, witness Oliver rejected arguments that the GIP should be delayed until an IRP or ISOP process is conducted. He asserted that delay could hinder the ability of ISOP to deliver benefits, and he stated that Duke is already engaging stakeholders to develop the ISOP process.

DEC witness McManeus responded to witnesses who expressed concern about the ratemaking aspects of DEC's GIP deferral request. She asserted that cost recovery is a separate and distinct process from deferral of costs. She stated that deferral would allow DEC the opportunity to avoid adverse financial impacts of regulatory lag, but only to the extent the Commission ultimately allows recovery of the deferred cost in a future proceeding. Witness McManeus stated that even if DEC were allowed to defer its GIP costs, the Company would still bear the risk of recovering the costs in a future rate proceeding.

Witness McManeus clarified that DEC is not requesting deferral of its GIP capital expenditures. Rather, DEC is requesting to defer the traditional revenue requirement amounts associated with the GIP capital expenditures. She stated that when the Company makes capital investments as part of the GIP, the cost to be deferred would be the depreciation and return on investment for the completed plant in service. She stated that if the Company spends $1.2 billion in capital over a three-year period, the deferred cost associated with that amount is not $1.2 billion, but instead is three years of annual depreciation and return on that investment, beginning at the date the assets are completed and in service. She explained further that the deferral would include the financing costs related to the amounts that are unrecovered during the period between the in-service date of the asset and when Company rates are updated to include cost recovery of the assets.

Witness McManeus disagreed with one of Public Staff witness Maness's recommended conditions for deferral. She stated that in his supplemental testimony filed February 25, 2020, witness Maness proposed to exclude deferral of a return on the balance of deferred incremental capital costs and incremental expenses. She stated that this return represents the financing costs the Company would incur between the time the GIP costs are incurred and the time that such costs are approved for recovery in future rates.

Witness McManeus disagreed with those witnesses who asserted that deferral would cause customers to bear the risk of cost overruns or GIP scope shortcomings. She stated that the Commission has full authority to address cost overruns or scope issues during a future general rate case when the deferred costs are presented for recovery, and DEC bears the full risk of any disallowances the Commission could choose to impose. During the consolidated evidentiary hearing, witness McManeus stated that by hosting its stakeholder process as directed by the Commission, DEC was able to assure that the GIP programs constitute grid modernization and hence are extraordinary, as opposed to customary spend. Consolidated Tr. vol. 6, 87. She testified further that having "been granted a regulatory deferral as a regulatory asset, . . . I think that's sort of a nod from the Commission to say we understand the costs you're talking about and we don't view them as inappropriate programs or inappropriate electric expenses that one should not ever recover from a customer, assuming that they are reasonable and prudently incurred." Consolidated Tr. vol. 9, 24.

During the consolidated evidentiary hearing, witness McManeus stated that DEC had spent $350 million on GIP from January 2018 through May of 2020. Consolidated Tr. vol. 9, 35. No party disputed these costs.

During the consolidated evidentiary hearing, DEC witness Oliver stated that the Company's capital spending estimates for the GIP programs relied on unit cost estimates that involve a range of cost uncertainty from -20% to +30%. Consolidated Tr. vol. 10, 23.

Stipulations

Public Staff Second Partial Stipulation

In their Second Partial Stipulation, DEC and the Public Staff addressed several issues, including the GIP. The Public Staff agreed to support deferral for the following GIP programs: (1) SOG, (2) IVVC, (3) ISOP, (4) Transmission System Intelligence, (5) Distribution Automation, (6) Power Electronics, (7) DER Dispatch Tool, and (8) Cyber Security. For all other GIP programs, DEC agreed to withdraw its request for deferral accounting.

The stipulating parties agreed that the Second Partial Stipulation constitutes only approval of the decision to incur GIP costs; the Public Staff reserved the right to review actual costs for reasonableness and prudence in the future. DEC and the Public Staff agreed to jointly develop biannual reporting requirements to track GIP expenditures that receive deferral treatment. This will include: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of SOG and IVVC; and (5) providing data and analyses that inform any significant changes to the scope of the SOG and IVVC programs. The first report would cover spending in the last six months of 2020.

DEC agreed to assess the cost-effectiveness of GIP projects in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, GIP deferral would be restricted to capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, and a return on the deferred balance during the deferral period. Deferral would cease upon the effective date of any general rate case in which the associated eligible plant is included in rate base. If no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, Duke would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes. Under the Second Partial Stipulation, GIP deferral would not include overhead or administrative and general costs, but the capitalized project costs may include a reasonable allocation of management and supervision costs.

During the consolidated portion of the evidentiary hearing, DEC witness Oliver stated that to his knowledge the Second Partial Stipulation with the Public Staff does not have a spending cap, nor does it include performance guarantees. Consolidated Tr. vol. 6, 33-34, 68. Witness McManeus confirmed that the Second Partial Stipulation does not include a spending cap. *Id.* at 94. She stated that the ROE impact for the eight GIP programs in the Second Partial Stipulation was a cumulative impact of 70 basis points in year three if the Commission were to deny the deferral, but DEC nonetheless pursued full GIP spending. *Id.* at 108. Witness Oliver said that the benefits of the programs, as stated in his direct testimony Exhibit 7 cost-benefit analyses, would be tracked under the Second Partial Stipulation. *Id.* at 16. Witness Oliver also stated that DEC will implement GIP regardless of whether the Commission approves the Company's deferral request but emphasized that the deferral would give DEC the ability to implement the GIP programs more quickly and cost-effectively. *Id.* at 56.

Commercial Group Stipulation

In the CG Stipulation Commercial Group agreed not to oppose or support DEC's GIP deferral requests. However, DEC agreed that any GIP costs that are allocated to its optional power service, time of use with voltage differential customers, shall be recovered through demand charges.

CIGFUR Stipulation

In the CIGFUR Stipulation CIGFUR agreed to support DEC's GIP deferral request but reserved the right to review and object to the reasonableness of specific project costs in future rate cases. DEC agreed to allocate GIP costs using the minimum system method and voltage differentiated allocation factors for distribution plant.

Harris Teeter Stipulation

In the HT Stipulation Harris Teeter agreed to support approval of GIP deferral but is not precluded from taking any position in future cost recovery proceedings. DEC agreed to allocate GIP costs to OPT-V customers via demand charges.

Vote Solar Stipulation

In the Vote Solar Stipulation, Vote Solar agreed to support DEC's deferral of costs for the following GIP programs: ISOP, IVVC, SOG, Distribution Automation, Transmission System Intelligence, DER Dispatch Tool, and the 44-kV Line Rebuild. The Vote Solar Stipulation states that Vote Solar believes that these investments will enable and support the greater use of DER. Vote Solar agreed not to oppose deferral of the other GIP programs' costs. Further, "to the extent that DEC enters into an agreement with other intervening parties agreeing to a cost cap," Vote Solar supports such cost containment measures. DEC committed to develop potential pilot GIP customer programs to increase the use of distributed resources prior to submission of its 2022 IRP. If DEC and Vote Solar agree that these programs are cost-effective and meet Commission requirements, DEC agreed to file them for approval, and Vote Solar agreed to support such approval. Vote Solar reserved its right to review and object to specific project costs in future rate cases.

NCSEA/NCJC et al. Stipulation

In the NCSEA/NCJC et al. Stipulation NCSEA and NCJC et al. agreed to support DEC's deferral request for: (1) ISOP, (2) IVVC, (3) SOG, (4) Distribution Automation, (5) Transmission System Intelligence, (6) DER Dispatch Tool, and (7) 44-kV Line Rebuild, stating that these programs will enable and support greater use of DER. For all other GIP investments, NCSEA and NCJC et al. do not oppose deferral.

For its part, DEC agreed that congestion relief will be a primary criterion in planning and decision-making regarding future transmission and distribution investment, and that DEC will implement the basic elements of ISOP in its 2022 IRP. Following the 2024 IRP, DEC agreed that it will provide hosting capacity analyses for a sample of circuits, contingent on the Commission approving recovery of the costs. In addition, DEC agreed to preview a distributed generation guidance map with the TSRG in third quarter 2020, incorporate input, and publish it. Finally, DEC agreed that its 2021 IRP will include details of how DERs and non-wires applications will be examined in ISOP.

During the consolidated portion of the evidentiary hearing, witnesses Alvarez and Stephens agreed that the programs supported by NCSEA and NCJC et al. would support renewable energy deployment or improve reliability. Consolidated Tr. vol. 8, 97.

DEC Joint Testimony

On August 5, 2020, DEC witnesses Oliver and McManeus filed joint testimony and exhibits in response to a July 23, 2020 order by which the Commission directed DEC to file supplemental GIP economic analyses. The DEC analyses showed the revenue requirement and rate impacts of approving deferral for the smaller group of GIP projects covered in the Second Partial Stipulation. Page 1 of GIP Exhibit 3 – Deferral Granted (Settlement) of that testimony showed that under the Second Partial Stipulation, deferral and a subsequent rate case in 2024 would produce a revenue requirement of $126.6 million in 2024 and a rate increase at that time of 3.8% for residential customers, 2.1% for general service customers, and 1.6% for industrial customers. This analysis used the ROE and capital structure agreed to in the Second Partial Stipulation.

Witness Oliver testified that if the Commission does not grant deferral accounting, the Company will likely vary its GIP spending from year to year, performing smaller pieces of GIP over a much longer timeframe, which would delay benefits for customers. He stated that the deferral mechanism would give DEC the ability to implement the GIP programs in a much more cost-effective, planned-out way, and to bring the benefits to customers sooner. Further, the deferral would allow DEC to accelerate the historical pace of GIP spending to better position DEC for the future. Consolidated Tr. vol. 6, 45-46.

Witnesses Oliver and McManeus jointly testified that in order to perform GIP work at the pace and scope that provides the most benefit to customers, DEC needs new and modern ways to recover costs and avoid regulatory lag that can harm the Company’s financial metrics and, in turn, customers.

DEC witness McManeus testified that investments in generating plant lend themselves much better to being able to manage regulatory lag than do distribution investments, but even with generation investments, there are deferrals. She further explained that, because of the short construction period for GIP investments, the Company is not allowed to record allowance for funds used during construction (AFUDC) for this spending. She stated that AFUDC represents the Company's financing costs during construction and that being able to record AFUDC allows DEC to capitalize those financing costs as part of plant for eventual rate recovery. This "allows the Company to be made whole" and avoids regulatory lag. Consolidated Tr. vol. 9, 31-32.

Witness Oliver further testified that DEC's GIP programs "are the core of grid modernization" because they provide two-way power flows, advanced distribution planning, the ability to control VAR flow from a central hub, the ability to control voltage at substations and on lines, and the ability to leverage AMI meter information. He said these are foundational to building a modernized grid. Making these investments now will make ISOP more effective than it would be otherwise. Tr. vol. 10, 30.

DEC Late-Filed Exhibit 5

On September 8, 2020, at the request of Commissioner Hughes during the consolidated evidentiary hearing, DEC filed Late-Filed Exhibit 5, which shows the revenue requirement savings that DEC expects from the GIP programs agreed to in the Second Partial Stipulation. That unverified exhibit shows a revenue requirement reduction of $8.3 million in 2023 and $9.2 million in 2024, growing to $56.9 million in 2032. The majority of the benefits in 2032 ($29.6 million) are due to fuel savings from the IVVC initiative.

Public Staff Supplemental Testimony

In his September 8, 2020 supplemental testimony, witness Thomas testified that during the update period of February through May 2020, DEC closed to plant $34.7 million of GIP investments. He stated that about $7.1 million of that was for SOG segmentation and automation projects on 58 circuits. Of those 58 circuits, only two were fully enabled, 13 were slated for enablement in 2020, and the remaining 43 are not expected to be fully enabled until 2021 or 2022. Thomas stated that DEC had told the Public Staff that the personnel who program the software to enable each segment had not been able to keep up with the increasing pace of expenditures. Thomas concluded that these investments nonetheless are "used and useful" and eligible for inclusion in rate base even though they were not fully enabled.

In his third supplemental and settlement testimony filed on September 9, 2020, witness Maness stated that he had performed a general overview of DEC's additional GIP testimony and exhibits that were filed on August 5, 2020. He expressed concern that DEC's filing did not appear to reflect the impact of any accumulated deferred income taxes. He also reiterated his recommendation that, if the Commission approves a GIP deferral, it should not decide on an amortization period at this time. He stated that there is no "natural" amortization period in this instance, and we do not know the circumstances that DEC will face when the deferred GIP costs are presented for amortization. Therefore, he testified, that it makes better sense to decide on a reasonable amortization period when the facts are clearer.

DEC Supplemental Rebuttal Testimony

DEC witness Oliver responded to witness Thomas's supplemental testimony by stating that the timeframe is longer than Duke would like between construction and enablement of SOG segmentation and automation projects. He stated that once DEC is fully staffed it will take about 12 weeks between construction work completion and enablement. Witness Oliver said that these 12 weeks are needed to schedule multiple interdependencies between the reliability engineers who create the device settings, the model builders who program the devices into the software and facilitate testing and validation, and coordination with grid management technicians to ensure devices present correctly in the distribution control center. Witness Oliver testified that as COVID restrictions ease, DEC intends to begin building the staff required to reach the targeted 12-week timeframe. He stated that meeting the 12-week timeframe can be an additional metric tracked pursuant to the Second Partial Stipulation.

Discussion and Conclusions

In its 2018 rate case DEC sought approval for a rider, or alternatively, for deferral accounting treatment, for a similar set of grid modernization programs referred to by the Company as Power Forward. The Power Forward proposal involved $13 billion in capital spending over ten years for both DEC and DEP. The Power Forward proposals were strongly contested by most parties to the 2018 rate case proceeding, including the Public Staff, and ultimately not approved by the Commission. In rejecting Power Forward, however, the Commission directed DEC to use an existing proceeding, such as the IRP docket, to inform the Commission as to its grid modernization needs and suggested that the Company collaborate with stakeholders in developing any future grid improvement programs. Tr. vol. 11 at 628-29. In response to the Commission's recommendation, the Company convened three in-person stakeholder workshops and a series of webinars addressing the Company's plans for grid improvement. *Id.* at 629. Witness Oliver stated that the Rocky Mountain Institute acted as a neutral facilitator in each of the three workshops and prepared detailed, post-project reports that were filed with the Commission at the conclusion of each workshop. *Id.* at 629-30. Witness Oliver testified that because of these stakeholder engagements the Company made significant changes to its portfolio of investments, provided cost benefit analysis and underlying data sources and work sheets for all applicable programs and projects to stakeholders, and responded to questions concerning distributed renewable energy resources. *Id.* at 630-31. The Commission recognizes the effort expended by the Companies to engage with stakeholders, as the Commission had directed them to do.

In the instant proceeding, subsequent to its initial request for approval to defer costs related to $1.3 billion in spending on 16 programs aimed at addressing its grid modernization needs, DEC worked with the Public Staff to reduce further its planned investment, and the Public Staff agreed to DEC's requested deferral accounting treatment for that investment. Specifically, pursuant to the Second Partial Stipulation, DEC seeks deferral of the capital costs associated with GIP investments made from June 2020 through December 2022 for the following programs, the descriptions for which are derived from witness Oliver's direct testimony (including his Exhibit 10) and augmented with testimony from the consolidated portion of the evidentiary hearing:

(1) Self-Optimizing Grid (SOG). This initiative has three components: capacity, connectivity, and automation. Capacity projects expand substation and distribution line capacity to allow customers to be served from two directions. Connectivity projects create tie points between circuits. Automation projects provide intelligence and control, enabling the grid to dynamically reconfigure around trouble and better manage distributed energy resources. The advanced distribution management system is software that leverages the intelligence from the grid with information from substation equipment, intelligent switches and distributed energy resources to optimize power flow and minimize the impact to customers when faults occur. It is the centralized system for managing the grid.

(2) Integrated Volt/VAR Control (IVVC). Allows the distribution system to optimize voltage and reactive power via remotely operated substation and distribution line devices such as voltage regulators and capacitors. The grid operator can lower the voltage to reduce peak demand or to reduce overall energy consumption and system losses. Witness Oliver stated that DEC plans to convert 60% of its circuits to IVVC over three years, focusing on suburban areas where customers are more likely to adopt rooftop solar and electric vehicles. Consolidated Tr. vol. 6, 59.

(3) Distribution Automation. Includes four programs. The hydraulic-to-electronic recloser program involves the replacement of oil-filled devices with modern, remotely operating reclosing devices that support continuous system health monitoring. The fuse replacement program replaces one-time-use fuses with automatic devices that reset themselves. The underground system automation program modernizes the protection and control in underground systems that serve critical, high-density areas such as urban business districts and airports. The system intelligence and monitoring pilot develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system.

(4) Transmission System Intelligence. DEC will replace electromechanical relays with remotely operated digital relays, implement intelligence and monitoring technology capable of providing asset health data to drive predictive maintenance programs, deploy remote monitoring and control of substation and transmission line devices, and install resiliency projects that leverage state of the art equipment such as digital relays, gas breakers and other equipment enabled with SCADA communication and remote monitoring and control capabilities to rapidly respond to system outages or disturbances.

(5) Integrated System Operations Planning (ISOP). Involves the integration and refinement of existing system planning tools and the development of new analytical tools. It is a multi-year program to build and integrate the tools and processes needed to accommodate an integrated approach to plan and

operate the electric utility system. One example is the Morecast circuit level load forecasting tool, which is necessary to enable the Advanced Distribution Planning tool.

(6) Distributed Energy Resource (DER) Dispatch Tool. Will provide system-wide visualization and control of large-scale DERs, enabling DEC to model, forecast and dispatch them. It will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements.

(7) Power Electronics for Volt/VAR Control. This limited deployment of advanced solid-state technologies like static VAR compensators will help DEC manage power quality issues associated with increasing DER penetration.

(8) Cyber Security. These programs include cyber security enhancement, protection from electromagnetic pulses and electromagnetic interference, a device entry alert system, and a distribution line cyber protection and secure access device management. During the consolidated portion of the evidentiary hearing, witness Oliver stated that the cyber-related portions of GIP are essentially the same efforts that DEC has been funding in the past, only the amount of spending is larger. Consolidated Tr. vol. 5, 39.

The Second Partial Stipulation constitutes agreement between the Public Staff and DEC as to the decision to incur GIP costs and the deferral accounting treatment of those costs. The Public Staff expressly reserved the right in the agreement to review actual costs incurred by DEC for reasonableness and prudence in future proceedings. Additionally, DEC and the Public Staff agreed to develop jointly biannual reporting requirements to track GIP expenditures that receive deferral treatment, including: (1) tracking costs for each program, including the number of devices installed, types of projects completed, or circuits modified or impacted; (2) reporting on a circuit and substation level; (3) summarizing actual benefits compared to projected benefits; (4) reporting the operational system impacts of SOG and IVVC; and (5) providing data and analyses that inform any significant changes to the scope of the SOG and IVVC programs. The first report would cover spending in the last six months of 2020. Additionally, DEC agreed to assess the cost effectiveness of GIP projects in an on-going manner and to undertake a cost-benefit analysis for its automated lateral device program.

Further, the Public Staff and DEC agreed that the costs deferred would be limited to only capital costs (return, property tax, and depreciation) related to plant in service and incremental expenses net of operating benefits, for plant placed in service between June 1, 2020, and December 31, 2022, as well as a return on the deferred balance of such costs during the deferral period. The deferral would cease upon the effective date of any general rate case in which the associated eligible plant is included in rate base. The Public Staff and DEC agreed that if no general rate case order recognizing the entirety of eligible plant in rate base is issued by December 31, 2024, DEC would cease deferral of all eligible net costs and carrying costs and consult with the Public Staff regarding the beginning of amortization of the deferred costs for regulatory accounting and ratemaking purposes.

In addition to the agreement with the Public Staff, DEC reached stipulations related to the GIP programs with 14 parties, including: (1) Vote Solar; (2) Harris Teeter; (3) BJ's Wholesale Club; (4) Ingles Markets; (5) Walmart; (6) Food Lion, (7) JC Penney; (8) Macy's; (9) CIGFUR; (10) NCSEA; (11) NCJC; (12) NCHC; (13) SACE; and (14) NRDC. Several of those stipulations address cost allocation issues related to costs incurred for the GIP programs, which are not ripe for decision by the Commission at this time. Because the issues of cost allocation for costs associated with the GIP programs are not before the Commission for a determination in this proceeding, the Commission considers them to be properly reserved for the cost recovery proceeding, which would be DEC's next general rate case.

Under North Carolina law, a stipulation entered into by less than all parties in a contested case "should be accorded full consideration and weighed by the Commission with all other evidence presented by any of the parties in the proceeding." *CUCA I*, 348 N.C. at 466. Further, "[t]he Commission may even adopt the recommendations or provisions of the nonunanimous stipulation as long as the Commission sets forth its reasoning and makes 'its own independent conclusion' supported by substantial evidence on the record that the proposal is just and reasonable to all parties in light of all the evidence presented." *Id.*

Because of the structure and scope of the stipulations reached with the various settling parties, the Commission concludes that the GIP programs for consideration are those contained in the Second Partial Stipulation, which includes a commitment by DEC to withdraw its request for deferral accounting treatment for individual GIP programs that are not specifically supported by the Second Partial Stipulation. The settlements with the other intervenors either provide express support for or non-objection to the deferral of costs associated with the programs specifically agreed to in the Second Partial Stipulation.

The Commission understands the Second Partial Stipulation, considered together with the settlements reached between DEC and other intervenors, to have resolved GIP-related issues between DEC and the majority of intervenors that filed testimony relating to GIP issues. The only parties whose active opposition to GIP in the form of filed testimony were not resolved through these settlements are CBD/AV, NC WARN, the Tech Customers, and CUCA.

The Commission concludes that the Second Partial Stipulation, as well as the additional settlement agreements, constitute material evidence in this proceeding with regard to the GIP-related issues and should be afforded significant weight by the Commission.

At the direction of the Commission the Company engaged with stakeholders to redefine its grid modernization plans following its 2018 rate case proceeding. The scope of the Company's GIP proposal was further narrowed though additional negotiation with the Public Staff, and programs that had been criticized as being routine operation expense as opposed to grid modernization were dropped from the proposal that ultimately was adopted in the Second Partial Stipulation. At the expert witness hearing Public Staff witness Thomas testified that the Public Staff had investigated each program included in the Second Partial Stipulation, focusing on costs and benefits, and has an understanding of what ratepayers are getting, in terms of fuel savings and reduced operational costs. The Commission is persuaded by the testimony of witness Thomas that the Public Staff has an understanding of the operational benefits that have been estimated by DEC and the type of reliability improvements that customers might see, Consolidated Tr. vol. 7, 69, and concludes that the Public Staff entered into the Second Partial Stipulation with this understanding. Also, the Commission gives weight to the testimony of DEC witness Oliver as to his confidence in the cost estimates underlying the GIP proposals as well as cost control measures that the Company will implement. Consolidated Tr. vol.10, 23-25, 42-43.

The Company and Public Staff witnesses provided significant reassurance to the Commission that the eight GIP programs included in the Second Partial Stipulation are defined on the record as to scope, implementation, and initial budgets; that the Company has significant experience in implementing similar programs in many cases; and that rigorous project management and evaluation mechanisms will be utilized by the Company in implementing and monitoring these programs. These mechanisms will include reporting to the Commission at six-month intervals on the progress of such implementation as anticipated in the Second Partial Stipulation.

The test historically utilized by the Commission in assessing the propriety of a request for deferral accounting treatment is whether the costs proposed for deferral are extraordinary in type and extraordinary in magnitude. Tr. vol. 20, 527-29. However, this test is not the exclusive basis upon which the Commission has previously allowed deferral of costs incurred by utilities, and, as was noted in the 2018 DEC Rate Order, the Commission may approve a deferral within a general rate case with parameters different from those applied in contexts other than general rate cases. 2018 DEC Rate Order at 149. Unlike the consideration of a deferral request outside of a general rate case when a single expense is being brought to the Commission's attention, in a general rate case the Commission has the benefit of a complete picture of the Company's financial health, of all of its expenses and revenues, and the impact of a deferral of future costs on the revenue requirement being approved in that general rate case. Therefore, the typical concerns are not an issue in the present case because the request is not being determined outside of a general rate case, but rather is being determined in a general rate case, a proceeding in which all items of revenue and costs are reviewed.

Additionally, the Commission's 2018 DEC Rate Order declared that "with respect to demonstrated [grid modernization] costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the 'extraordinary expenditure' test." *Id*. Public Staff witness Maness explained that the Public Staff took special notice of language in the Commission's 2018 DEC Rate Order that suggests leniency regarding the magnitude of costs or financial impacts necessary to justify deferral. Consolidated Tr. vol. 7, 32, 48; tr. vol. 20, 538. Further, in explaining why the Public Staff opposed the

Company's Power Forward proposal but supported the GIP proposal set forth in the Second Partial Stipulation, witness Maness indicated that the Power Forward rider proposal was not clear on whether and the extent to which costs would be reviewed, but the Second Partial Settlement does establish and provide for rigorous review at the time the Company seeks cost recovery. Tr. vol. 7, 44. Public Staff witness Maness also expressed concern at the Company's position that, absent deferral approval, the Company would reduce spending on the GIP programs by 80%. *Id*. at 45. Finally, Public Staff witness Maness testified that the Public Staff "agreed to the settlement in terms of settling all of the issues in the case, and there was give-and-take amongst all of them" and further that "in the interest of settling the case, [the Public Staff] think[s] that it's acceptable for deferral to be approved for the expanded scope of programs that are reflected within the settlement." *Id*. at 49. Witness Maness made clear that the Public Staff was not generally abandoning its initial position in the proceeding, which involved application of the traditional deferral test, but that in the interest of settlement of issues agreed to the GIP proposals as reflected in the Second Partial Stipulation.

Given the evidence of record, the Commission accepts the terms of the Second Partial Settlement as to the GIP proposals, including the request for deferral accounting treatment. However, in approving the request for deferral accounting treatment for the GIP proposals set forth in the Second Partial Stipulation, the Commission deems it necessary and appropriate to limit the GIP costs that will be allowed deferral accounting treatment to $800 million, consistent with DEC's planned spending, in order to provide an incentive for DEC to manage its GIP spending cost-effectively and mitigate the risk of over-spending. In light of the fact that the Commission retains the ultimate authority to deny recovery of imprudently incurred or unreasonable costs — even if such costs have been previously deferred — the Commission finds that adequate protections against risks inherent in the design, budgeting, implementation, and monitoring for the eight settled GIP programs are adequately addressed in the record, in the Second Partial Stipulation, and by the implementation of the $800 million limitation on the deferral.

NC WARN witness Powers testified that the Commission should reject the Company's GIP as unreasonable on the basis that the GIP projects are indistinguishable from traditional spend projects, with no formal applications or associated evidentiary process to evaluate the reasonableness or potential alternatives for these proposed expenditures. Witness Powers also contended that the stakeholder workshops used to develop the GIP were essentially sales presentations by the Company that did not adequately review the scope and cost of the GIP. Similarly, CBD/AV witness Ryan argued, generally, that the Company has failed to provide sufficient explanation as to how the GIP programs are different from traditional spend and have failed to demonstrate that the GIP programs providing requisite information concerning how these costs affect ratepayers and the public interest. In spite of the contentions of NC WARN and CBD/AV, the Commission concludes that the work undertaken by the Company in the stakeholder process to refine its grid modernization proposals and, thereafter, the additional work with the Public Staff to further limit the proposals and associated spending distinguish the proposals from previous proposals. This conclusion is further supported by the unrebutted testimony of Company witness Oliver, who described the GIP program proposals as "foundational" to managing the transition from grid consisting primarily of one-way power flows to a two-way power flow dynamic. Consolidated Tr. vol. 5, 40.

CUCA witness O'Donnell generally took issue with the GIP proposals, expressing concern over costs associated with the programs and the similarity to the Power Forward proposals that had been rejected by the Commission. However, witness O'Donnell did provide several recommendations as to how the Commissions should address the GIP proposals, including making cost recovery contingent upon the Company meeting the reliability targets as set forth by DEC in its cost benefit analyses and allowing cost recovery if and only if the reliability targets are reached every year. The Commission notes the concerns expressed by CUCA witness O'Donnell but gives weight to the fact that, per the terms of the Second Partial Stipulation, Duke and the Public Staff will jointly develop metrics to monitor the implementation and measure the effectiveness of the programs. Further, DEC agreed to report such metrics, including cost-effectiveness, for each of the agreed programs on a regular basis beginning with expenditures made during the last six months of 2020. On this point, at the expert witness hearing DEC witness Oliver testified that the Company will be able to measure the performance of and the benefits achieved by the programs. Additionally, Public Staff witness Thomas indicated comfort with the parties' ability to measure GIP program performance and confirmed the Public Staff's intention to monitor GIP program performance closely. Thus, the Company has committed to report to the Commission on the effectiveness and cost-effectiveness of the programs. The Commission will hold the Company to this commitment, and the Commission anticipates that these data will be taken into consideration by the Commission in the cost recovery proceedings.

Tech Customers witness Strunk testified that approval of cost deferral could result in regulatory imbalance, noting that the deferral accounting transfers risks from the Company to its customers and will raise customer rates to the benefit of the Company. Witness Strunk also testified that the Company's GIP proposals are substantially similar to Power Forward, for which the Commission elected not to approve deferral accounting. Finally, witness Strunk argued that even if deferral were appropriate for GIP costs, it is premature for the Commission to authorize the deferral given that the Company is also in the planning stages of implementing ISOP and that the ISOP process could affect the nature and level of investment required under the Company's GIP. The Commission acknowledges the link between the GIP proposals set forth in the Second Partial Stipulation and Power Forward. But as previously discussed, the Commission concludes that the work undertaken by the Company in the stakeholder process to refine its grid modernization proposals and, thereafter, the additional work with the Public Staff to further limit the proposals and associated spending distinguish the proposals in the Second Partial Stipulation from previous proposals. In addition, the Commission notes witness Strunk's warning regarding transfer of risks but concludes that when the costs are before the Commission for recovery, the burden will be on the Company to prove that those costs were reasonably and prudently incurred, which will mitigate this risk. Further, the Commission intends that the $800 million limit on the deferral will serve as a guardrail against over-spending by the Company.

The Commission takes note of Tech Customers witness Strunk's testimony highlighting the tension between implementing a grid modernization effort now, versus waiting for implementation of the ISOP process that is under development. The Commission is persuaded by witness Oliver's testimony that the majority of the GIP programs are foundational and should be pursued at this time. However, the Commission agrees with the Tech Customers that additional grid modernization investments beyond 2022 should be informed by the ISOP process. Thus, going forward the Commission expects any request related to grid modernization investments to be informed and justified by the ISOP process.

The Commission has carefully reviewed the evidence on DEC's GIP proposal in this docket and concludes that acceptance of the Second Partial Stipulation's provisions between the Public Staff with DEC related to the GIP programs is appropriate and is supported by material and substantial evidence of record.

The Commission's acceptance of the GIP provisions of the Second Partial Stipulation is limited. The Commission's decision simply allows DEC to treat costs incurred in pursuing the settled GIP programs as regulatory assets pending a prudence and reasonableness determination in a later rate case. DEC remains fully at risk for the reasonableness and prudence determination of its GIP costs and for its ultimate recovery from customers, as would be the case if DEC simply undertook these programs without a deferral and then sought recovery of the costs in a rate case. The only difference is that deferral of these costs allows certain between-rate-case earnings impacts of these costs to be held on the books of DEC as a regulatory asset and preserves them for possible future recovery if they are determined by the Commission, in a future proceeding, to be just and reasonable, prudently incurred, and otherwise eligible for recovery from customers.

The Commission concludes that the parties have compromised significantly to reach agreement, as evidenced by the Second Partial Stipulation, and deferral treatment for the GIP programs identified in the Second Partial Stipulation is reasonable and in the public interest. The Commission recognizes that the Company has undertaken stakeholder engagement efforts since the last rate case and made considerable efforts in this regard, as directed by the Commission. Through the stakeholder process, and continuing through this rate case proceeding, the Company has significantly narrowed its planned spending. The accounting deferral request, as modified by the Second Partial Stipulation with the Public Staff, and supported by other intervenor settlement agreements, represents a set of programs that can be classified as grid modernization, along with reporting requirements that will ensure collaboration and transparency as investments are made. The approval for deferral accounting treatment is limited to $800 million, which will incent Duke to manage its spending, and any amounts actually spent and deferred by the Company will be subject to review for reasonableness and prudence before any such costs are passed on to customers. Finally, the deferral accounting treatment approved in this proceeding shall be considered specific only to this case in light of the evidence of record in this proceeding and shall not be given any precedential value by the Commission with regard to any future general rate case proceeding or deferral request or any other proceeding before the Commission at any point in the future.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 42–48

Tax Act Issues

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations and CIGFUR Stipulation; the testimony and exhibits of DEC witnesses De May, McManeus, Newlin, Hager, Panizza, and Hevert, Public Staff witnesses Boswell and Hinton, CBD/AV witness McIlmoil, CIGFUR witness Phillips, CUCA witness O'Donnell, and Tech Customers witness Strunk; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

Witness De May

Witness De May noted that the impacts of the Federal Tax Cuts and Jobs Act of 2017 (Tax Act) have been incorporated into the Company's request, as outlined in the testimony of witnesses Panizza and McManeus.

Witness McManeus

Witness McManeus described DEC's proposal to refund to customers through a rider the federal and state corporate income tax amounts related to the Tax Act and recent reductions to North Carolina corporate income tax rates. Witness McManeus provided McManeus Exhibit 4 with her direct testimony to illustrate the proposed rider to refund EDIT to customers.

Witness McManeus noted that DEC, in its Sub 1146 rate case, adjusted its rates to reflect reduced income tax expense related to the reduction in the federal corporate income tax rate from 35.00% to 21.00% as promulgated in the Tax Act, which became law on December 22, 2017. She noted that the lower federal corporate income tax rate continues to be reflected in proposed rates in this proceeding.

Witness McManeus further noted that in Sub 1146 the Commission ordered the Company to maintain the federal protected and unprotected EDIT in a regulatory liability account for three years, or until DEC's next general rate case, whichever was sooner. Witness McManeus stated that in compliance, DEC is proposing a method of returning EDIT to its customers through a rider.

Witness McManeus maintained that DEC's proposed Rider EDIT-2[12] contained five categories of benefits to customers, as follows:

(1) Federal EDIT – protected;
(2) Federal EDIT – unprotected, Property, Plant & Equipment (PP&E)-related;
(3) Federal EDIT – unprotected, non-PP&E related;
(4) Deferred (provisional) revenue – federal income tax; and
(5) NC EDIT.

1. Federal EDIT – protected

Witness McManeus stated that these amounts are generally related to PP&E, and there are specific IRS requirements mandating that these amounts not be returned to customers quicker than prescribed by the IRS. Witness McManeus testified that the amortization period DEC is using for protected EDIT is called the average rate assumption method (ARAM), and results in a Year 1 amortization rate for this category of 2.53%. She noted that protected amounts ultimately become unprotected over time and, as such, DEC estimated this amount and captured this transition from the protected to unprotected category on McManeus Exhibit 4, Page 1, Line 3.

2. Federal EDIT – unprotected, PP&E-related

Witness McManeus stated that these amounts are also related to PP&E but do not fall under the IRS guidelines for protected status. She stated that because DEC would have paid these amounts to the IRS over the remaining life of the underlying property, DEC is proposing to return these amounts to customers over 20 years. She further stated that this approach balances the customers' and the Company's interests, minimizing customer rate volatility and addressing the Company's cash flow concerns.

3. Federal EDIT – unprotected, non-PP&E related

Witness McManeus noted that these amounts are not related to PP&E but are related to items such as regulatory assets and liabilities, and other balance sheet items. She stated that as noted by DEC witness Panizza, these items have an average life of approximately seven and one-half years. Witness McManeus testified that DEC is proposing to return these amounts to customers over a five-year period. She also stated that the Company has included in this category amounts transitioning from the protected category to unprotected status.

4. Deferred (provisional) revenue – federal income tax

Witness McManeus stated that as directed by the Commission in Docket No. M-100, Sub 148, DEC began deferring, effective January 1, 2018, the impact on

[12] Rider EDIT-1 represents the state EDIT that is being returned to customers through a four-year Rider as approved in DEC's Sub 1146 rate case.

customer rates of the reduction in the federal corporate income tax rate from 35.00% to 21.00%. Witness McManeus noted that beginning August 1, 2018, new rates approved by the Commission in Sub 1146 reflected the lower federal corporate income tax rate. She stated that after August 1, deferral amounts are related to continuing accrual of returns on the deferral balance. She testified that McManeus Exhibit 4, Page 1, Line 8, shows the projected balance of this liability as of January 31, 2020. She further stated that DEC proposes to refund this amount to customers over a five-year period. Witness McManeus stated that DEC will continue to defer the impact from February 1, 2020, through the effective date of new rates in this case. She also noted that those additional amounts are not being estimated now but will be included in the Year 2 EDIT rider calculation.

5. NC EDIT

Witness McManeus testified that like the EDIT that results from the reduction in the federal corporate income tax rate, there are EDIT balances that resulted from the reduction in the North Carolina corporate income tax rate. She noted that in Sub 1146 the Commission approved a four-year state EDIT rider to return EDIT resulting from reductions in the state corporate income tax rate in prior years (Rider EDIT-1). Witness McManeus commented that the state EDIT rider currently in place does not include EDIT related to the reduction in the North Carolina corporate income tax rate from 3.00% to 2.50%, effective January 1, 2019. She stated that DEC is proposing to incorporate the refund of the new state EDIT in the EDIT proposed in this case (Rider EDIT-2), over a five-year period.

Witness McManeus stated that the proposed rider will include the annual amortization for each of these five categories of benefits. She states that the North Carolina retail amounts can be seen on McManeus Exhibit 4, Page 1, Columns A through E. Witness McManeus noted that since these collected EDIT amounts reduce rate base, DEC's rate base will increase as they are refunded to customers. She stated that, as such, the rider also calculates the adjustment to return on rate base related to the increase in rate base resulting from the refund of EDIT to customers, as shown in McManeus Exhibit 4, Page 2, Column L. She stated that Column M shows the revenue requirement equal to the sum of the amortization and return. Witness McManeus testified that Column N shows the revenue requirement grossed up for the Commission's regulatory fee and uncollectible expense. Witness McManeus stated that the amount in the Year 1 row on McManeus Exhibit 4, Page 2 of a $154.6 million decrease is the rider amount that is being proposed in this case.

Witness McManeus explained that the Year 1 rider amounts are based on the balance of EDIT at December 31, 2018, as described by DEC witness Panizza and are updated to reflect the expected balance at July 31, 2020, when the proposed rider is expected to be implemented. She stated that this projection will be further updated to reflect actual January 31, 2020 balances, as well as the latest ARAM rate, prior to the hearing.

Witness McManeus stated that years two through five are shown for illustrative purposes. She noted that the actual rider amounts for those years may change based on several factors. Witness McManeus testified that first, the annual amortization amounts will be recalculated to account for any additional adjustments to any of the balances on rows one through five of McManeus Exhibit 4.

Witness McManeus testified that a second factor that would impact the calculation of the rider beyond year one is changes in the ARAM rate. She explained that the Company updates this rate annually and the most current rate must be used when establishing customer rates.

Witness McManeus further testified that a third factor that would impact the calculation of the rider beyond year one is the impact of future rate cases. She stated that in future rate cases, the EDIT balance in base rates shown in Column J and the rate of return used to calculate Column L of McManeus Exhibit 4, Page 2 would be updated based on what is approved in future cases. Witness McManeus also stated that the retention factor used to calculate Column N will be updated to reflect any future changes in the license fee or public utility assessment fee rates as needed.

Witness McManeus testified that DEC proposes to file the rider amounts, along with the spread to the classes and derivation of the rate for each subsequent year, with the Commission annually in this rate case docket by April 30, for rider rates effective July 1.

Witness McManeus filed supplemental direct testimony wherein she updated the EDIT calculation to reflect known changes to the EDIT balances and amortization amounts as of January 2020. She noted that the updated numbers reflect the completion of Duke Energy's 2018 federal income tax return. Witness McManeus also stated that the annual amortization percentage for protected EDIT has been updated to an actual amount that aligns with the most recently filed federal income tax return that is the Company's best estimate for the following year's protected EDIT amortization. She stated that this update is necessary to comply with federal tax normalization rules referenced in her direct testimony. Witness McManeus explained that a second amount that has been updated is related to the North Carolina EDIT component of the rider to reflect minor revisions to the EDIT amount.

Witness Newlin

Witness Newlin explained how tax reform could create concerns for customers and for utilities. He noted that deferred taxes are not large pools of money that the Company is holding in an account. Witness Newlin stated that, instead, they are collections that occur over time based on the life of the underlying assets, which are used by the Company during the deferral period to invest in the business to better serve customers. Witness Newlin asserted that customers have benefitted from the use of deferred taxes through the Company's use of these zero interest loans to finance its business rather than incurring financing costs that are passed on to customers. Witness Newlin argued that when the tax rate changes, either up or down, leveraging the over and under-collection of these funds in a proper and principled manner benefits both the Company and its customers. He maintained that if adjusting rates to account for tax changes is done in a haphazard manner, it can cause rate volatility and harm to customers as well as the financial health of the utility.

Witness Newlin stated that for unprotected EDIT, the question becomes what is the appropriate flowback period to customers that balances both the best interest of customers and the financial strength of the Company and the cash flows of the Company. Witness Newlin maintained that the Company's proposed 20-year flowback of federal PP&E-related unprotected EDIT more closely matches the underlying asset lives and smooths out the Company's cash flow.

Witness Newlin testified on steps taken by several other state utility commissions to mitigate the negative impacts of tax reform.

Witness Hager

Witness Hager explained the allocation factors used in the proposed EDIT rider. She noted that DEC has allocated the benefits in the EDIT-2 Rider in Rate Design exhibits to the classes based on the accumulated deferred income tax allocator. Witness Hager stated that she has reviewed this allocation and believes it is reasonable based on cost causation principles. She maintained that since the EDIT amounts were previously part of accumulated deferred income taxes as explained by DEC witnesses McManeus and Panizza, this is consistent with how the amounts were allocated prior to the federal tax rate change and reasonably reflects how the benefits were created.

Witness Panizza

Witness Panizza noted that the Tax Act reduction in the corporate tax rate is accompanied by many other provisions having varying impacts on the revenue requirement, and that these impacts must be considered particularly as they relate to cash flow.

Witness Panizza stated that DEC's $2,175 million (or $2.2 billion) of EDIT, as of the end of 2018, is in three different buckets. Witness Panizza explained that one bucket contains approximately $1,193 million (or $1.2 billion) as of the end of 2018 of what is called protected EDIT, which is EDIT related to the Company's investment in PP&E whose flowback treatment is expressly made subject to IRS normalization rules by the Tax Act. He noted that the IRS normalization rules require protected EDIT to be flowed back over the remaining lives of the property giving rise to the deferred tax balance. Witness Panizza noted that the remaining EDIT, totaling approximately $982 million, as of the end of 2018, is unprotected under IRS rules, and therefore subject to flowback in a timeframe open to discretionary action by the Commission. Witness Panizza stated that the lion's share of unprotected EDIT, totaling more than $783 million still relates to the Company's investment in PP&E although it is in the second bucket of EDIT. Witness Panizza explained that this portion of unprotected EDIT is not required to be normalized under the Tax Act. Witness Panizza asserted that although both buckets are property-related, the Internal Revenue

Code protects one and not the other. He argued, however, that the rationale for normalization applies to this unprotected portion of EDIT as much as it applies to protected EDIT, and so normalization at some level is appropriate. He stated that assets represented in this bucket have an average life of approximately 23 years for DEC, although the Company's proposal uses a shorter 20-year period over which to accomplish this flowback.

Witness Panizza explained that the third and final bucket, totaling approximately $199 million, as of the end of 2018, is unprotected EDIT. He stated that for DEC, the assets in this bucket include a variety of things, including certain regulatory assets with a two-year life, pension-related EDIT with 12- to 20-year lives, and EDIT that transitioned from protected to unprotected during 2018. Witness Panizza stated that the average life of these assets is six and one-half years.

Witness Panizza testified that while these balances are as of the end of 2018, the Company has made and may make additional adjustments to these amounts in 2019, as protected amounts ultimately become unprotected over time.

Witness Panizza testified in support of the Company's proposed 20-year flowback period and contended that a gradual return of EDIT over the life of the capital asset being depreciated balances the customer and the Company's interests.

He stated that DEC's proposal complies with accounting requirements while preserving DEC's credit rating by not creating undue pressure on cash flows.

CBD/AV Direct Testimony

Witness McIlmoil

Witness McIlmoil stated that DEC is proposing to offset its requested increase by approximately $154.6 million in the first year and by lower amounts in subsequent years to refund to ratepayers tax benefits DEC received as a result of the Tax Act. He noted that the net impact of the refund would be to lower the increase in annual revenues to $290.8 million representing an overall net increase in revenues, again for the first year only, of 6.00%. Witness McIlmoil maintained that as the refund value declines in year 2 and beyond the annual revenue requirement, and thus the percent increase in revenues, would subsequently increase above the year 1 values, resulting in higher rate and cost impacts for DEC ratepayers over time. Witness McIlmoil asserted that these impacts will be further exacerbated by the expiration of the EDIT-1 Rider after August 1, 2022.

CIGFUR Direct Testimony

Witness Phillips

Witness Phillips stated that DEC is proposing to credit customers through Rider EDIT-2 for five categories of taxes that DEC is obligated to refund. He maintained that the Commission should use its discretion to require DEC to refund federal unprotected EDIT as expediently as possible to the ratepayers. Further, witness Phillips urged the

Commission to reject DEC's proposal to refund the federal unprotected PP&E-related EDIT over a prolonged period.

CUCA Direct Testimony

Witness O'Donnell

Witness O'Donnell stated that DEC is seeking a total increase of $445 million that accounts to an overall increase of 9.20%. He noted that this increase does not reflect the return to customers of EDIT. Witness O'Donnell maintained that as a result of the return of the EDIT to those to which it is owed, the net increase is $291 million which equates to a net 6.00% overall increase.

Witness O'Donnell asserted that the Tax Act created EDIT that needs to be returned to the North Carolina retail customers of DEC. Witness O'Donnell noted that the rate increases sought by DEC in this rate case are significantly lower when the return of EDIT is considered.

Public Staff Direct Testimony

Witness Boswell

Witness Boswell noted that DEC did not make an adjustment to exclude any EDIT from rate base but instead proposes to handle each of the five categories in a single rider, with rate changes occurring each year based on the proposed amortizations for these categories, which range from 39.6 years to five years. Witness Boswell asserted that the categories of refunds should be handled separately due to the differing natures of the amounts and the amortization periods. She maintained that such handling provides a more transparent means of tracking the Tax Act and state tax-related refunds to customers for each year. Therefore, witness Boswell recommended several adjustments regarding federal EDIT.

First, witness Boswell recommended an adjustment to remove the federal protected EDIT from the EDIT Rider proposed by DEC and instead leave the amount in base rates. She proposed to amortize the protected EDIT balance over 39.6 years in base rates and to remove the first year of amortization from the deferral amount for purposes of this proceeding.

Next, witness Boswell asserted that DEC has artificially created two categories of federal unprotected EDIT for purposes of its proposal: federal unprotected PP&E which DEC proposes to return to ratepayers over 20 years and federal unprotected other which DEC proposes to return to ratepayers over five years. She contended that the tax normalization rules are very clear, and either EDIT is protected or it is not. Witness Boswell stated that DEC's proposed classification of PP&E-related federal unprotected EDIT is not supportable by any logical accounting or ratemaking principle and should not dictate this Commission's decision as to what is a reasonable amount of time within which to return these funds to ratepayers. She argued that these funds rightfully belong to the ratepayers and should be returned to them as soon as reasonably possible. Witness Boswell recommended that the Commission remove the entire federal unprotected EDIT regulatory liability from rate base and place it in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs. She asserted that the immediate removal of unprotected EDIT from rate base increases the Company's rate base (and therefore customer rates) and mitigates regulatory lag that may occur from refunds of unprotected EDIT not contemporaneously reflected in rate base. Witness Boswell asserted that refunding the federal unprotected EDIT over five years allows DEC to properly plan for any future credit needs while refunding ratepayer dollars in a reasonable time.

Witness Boswell further testified that she made an adjustment to remove from DEC's proposed single Rider the overcollection of federal taxes which resulted from the reduction in the federal corporate income tax rate from 35.00% to 21.00% and placed it into a separate levelized rider to be amortized over a one-year period. Witness Boswell stated that she removed the balance from the working capital schedules since she is recommending a refund over one year. She noted that the one-year amortization period is consistent with the period approved by the Commission in the most recent rate cases of Aqua North Carolina, Inc., Carolina Water Service, Inc. of North Carolina, and Piedmont Natural Gas Company, Inc.

Witness Boswell recommended removing the entire state EDIT balance from rate base, as DEC has in its proposed adjustment, and placing it in a separate rider to be returned over one year with a return on the balance. She noted that this is consistent with the Commission's order in a recent Dominion Energy North Carolina docket, Docket No. E-22, Sub 532.

Witness Hinton

Witness Hinton provided testimony on how the Public Staff's proposals on the flowback of federal unprotected EDIT impact DEC's credit metrics. He noted that DEC has provided the Public Staff with the projected credit metrics, specifically the Cash Flow from Operations excluding changes in working capital over total debt (FFO/Debt) under both the Public Staff's proposed five-year flowback proposal and DEC's proposed 20-year flowback proposal for federal unprotected EDIT. He stated that the 20-year flowback of federal unprotected EDIT results in a higher average projected FFO to debt ratio of approximately 42 basis points. Witness Hinton maintained that as noted in Moody's October 31, 2019 Credit Opinion, an FFO to Debt ratio that is between 24% and 26% qualifies for an "A" rating. Witness Hinton noted that given that the FFO/Debt metric is only below 24% in 2021 and the other metrics are 24% or 25% through 2023, he contends that unexpected financial developments would have to occur that reduced DEC's cash flow from operations or cause the Company to issue more debt to trigger a downgrade.

Witness Hinton noted that Moody's places 40% weight on financial strength as measured by its quantitative financial metric, 50% weight on the utility regulation, and 10% weight on utility diversification. He stated that the 50% weight on regulation focuses on two areas: the regulatory framework and the ability to recover costs and earn returns. Witness Hinton maintained that the regulatory framework relates to rate setting by the governing body, credit supportive legislation that is responsive to the needs of the utility, and the way the utility manages the political and regulatory process. He stated that the ability to recover costs and earn returns on its investments relates to the assurance that the regulated rates will be based on prescriptive and clear ratemaking methods. Witness Hinton asserted that while awarding the least weight in its rating methodology to diversification, Moody's positively views utilities with multinational and regional diversity in terms of regulatory regimes and diversity in the economics of its service territories.

Witness Hinton maintained that DEC has other means to finance the EDIT over a five-year period that would not deteriorate DEC's FFO/Debt metrics. He noted that DEC's financial forecast indicates that DEC will continue every year to be financed with 48% to 47% long-term debt and 52% to 53% common equity through 2023. Witness Hinton stated that from 2020 through 2023, the Company's filings indicate that the Company plans to issue a total of $2.40 billion in long-term debt and infuse $4.05 billion to Duke Energy Corporation (the parent). He further stated that this indicated that an option may exist for DEC to offset some of its debt issuances through a reduction in its planned contributions to its parent, which would allow DEC to maintain its credit ratings or, in the event of a downgrade, the ability to restore its current credit ratings. Witness Hinton noted that DEC witnesses De May and Newlin stressed the importance of maintaining DEC's credit quality, which Moody's Investor Services places as the highest-rated among Duke Energy Corporation and its other five electric utility subsidiaries as follows:

Moody's Credit Ratings

	Long-Term Issuer Rating	**First Mortgage Bonds**
Duke Energy Corporation	Baa1	NA
Duke Energy Carolinas	A1	Aa2
Duke Energy Progress	A2	Aa3
Duke Energy Florida	A3	A1
Duke Energy Indiana	A2	Aa3
Duke Energy Kentucky	Baa1	NA
Duke Energy Ohio	Baa1	A2

Witness Hinton also noted that Duke Energy Corporation said it will issue approximately 29 million shares of common stock which will result in approximately $2.5 billion of net proceeds. He stated that this additional equity could allow DEC to decrease its projected equity infusions up to the parent company, which would alleviate the need to issue the amount of new debt and reduce the possibility of a downgrade.

Witness Hinton stated that DEC expects that a one-notch downgrade by Moody's to Aa3 would increase the investor-required bond yield by 5 basis points, and noted that DEC maintains that this estimate was based on market conditions associated with the January 7, 2020 issue of 2.45%, 10-year bonds. Witness Hinton stated that DEC noted that the differential would be greater than 5 basis points if the bond market was under dramatic volatile periods and stated that following DEC's acknowledgement of the current bond market, it is worth noting that Moody's A-rated long-term utility bond yields are the lowest in over 30 years. Witness Hinton asserted that considering the Company's financial forecasts, it is his opinion that the added cost of debt capital from a downgrade to an Aa3 rating will not be burdensome on the Company.

Witness Hinton further stated that if DEC is downgraded, it is not likely that DEC will remain at that level for an extended period. He asserted that while a downgrade to Aa3 is not likely, recent history indicates that if it did occur, it would probably last less than five years. Witness Hinton noted that since 1973, DEC has had six upgrades and four downgrades and that it does not appear that any downgrade resulted from the 1986 change in the federal corporate income tax rate.

Witness Hinton asserted that after his review of the FFO/Debt credit metrics, he supports the refund of federal unprotected EDIT over five years as recommended by witness Boswell. He stated that it is unlikely that spreading the EDIT over five years will result in a debt rating downgrade and that a five-year flowback is reasonable and fair to DEC's ratepayers and the Company.

Tech Customers Direct Testimony

Witness Strunk

Witness Strunk testified that based on a survey of regulatory precedent during the last 12 months, he recommends that the Commission shorten the amortization of federal unprotected EDIT to no more than five years. Witness Strunk maintained that this would provide an offset to DEC's proposed rate increase and will track the prevailing treatment by other regulatory commissions. Witness Strunk noted that he is agreeable to DEC's proposed amortization periods for federal unprotected non-PP&E EDIT (five years), federal provisional revenues (five years), and state EDIT (five years). Witness Strunk provided a survey of news articles during the past 12 months that pertain to federal unprotected EDIT. Witness Strunk stated that the survey evidence supports his position that DEC's 20-year flowback period for federal unprotected EDIT is excessively long.

DEC Rebuttal Testimony

Witnesses De May and Hevert

Witness De May testified that the intervenors propose that the Commission require the Company to flow back hundreds of millions of dollars in EDIT immediately, or in the very short term, which is in stark contrast to the intervenors' position on the recovery of coal ash costs (if over time then without interest at the Company's weighted average cost of capital).

Witness D'Ascendis noted in his rebuttal testimony that the March 2015 Report by Moody's mentioned in witness Woolridge's testimony makes it clear that utilities' cash flows have benefited from increased deferred taxes which themselves were due to bonus depreciation. He stated that the report also notes that the rise in deferred taxes eventually would reverse. Witness D'Ascendis stated that in January 2018, Moody's spoke to the effect of the reversal on utility credit profiles in the context of tax reform as follows:

> Tax reform is credit negative for US regulated utilities because the lower 21% statutory tax rate reduces cash collected from customers, while the loss of bonus depreciation reduces tax deferrals, all else being equal. Moody's calculates that the recent changes in tax laws will dilute a utility's ratio of cash flow before changes in working capital to debt by approximately 150-250 basis points on average, depending to some degree on the size of the company's capital expenditure programs. From a leverage perspective, Moody's estimates that debt to total capitalization ratios will increase, based on the lower value of deferred tax liabilities.

Witness D'Ascendis noted that in June 2018, Moody's changed its outlook on the U.S. regulated sector to "negative" from "stable".

Witness McManeus

Witness McManeus testified that DEC does not oppose rider treatment for EDIT but opposes the specific rider treatment as recommended by the Public Staff. In addition, she stated that DEC does not agree with the recommendations of Tech Customers witness Strunk.

Witness McManeus contended that witness Bowell's exhibits reflect only one side of the $80 million transition of EDIT from the protected to the unprotected EDIT categories between January 1, 2019 and July 31, 2020. She stated that while witness Boswell's levelized federal EDIT – Unprotected Rider does reflect the effect of this transition and the resulting flowback of greater revenue reductions, her calculation of the protected EDIT in base rates excludes the off-setting transition impact and consequent increase in rate base.

Witness McManeus asserted that this is not correct and is not consistent with how this transition is treated in McManeus Exhibit 4 filed with her direct testimony which captures both offsetting effects of the transition on page 1, line 8 of McManeus Exhibit 4 when calculating rate base return impacts in the EDIT rider on page 2 of McManeus Exhibit 4, columns A, K, and L in year 1.

Witness Newlin

Witness Newlin noted that Tech Customers witness Strunk cited 34 separate news articles in the past 12 months as evidence of shorter flowback periods, 13 of which include flowback provisions exceeding the five-year time period proposed, and two which include flowback periods as long as 44 years. Witness Newlin maintained that without the full context of the associated orders, it is impossible to determine the size and scale of the deferred taxes returned and expected cash flow impacts in the context of the respective utility's credit metrics and capital needs. He asserted that DEC faces unprecedented amounts of capital needs in the coming years and already stressed credit metrics.

Regarding Public Staff witness Hinton's testimony, witness Newlin maintained that his analysis focuses on EDIT flowback in isolation and does not consider the cumulative impact of other potentially credit negative proposals by the Public Staff.

Addressing witness Hinton's statement that a downgrade will only last five years, witness Newlin maintained that five years is a long time and witness Hinton's presumption is overly optimistic.

Stipulations

Public Staff First and Second Partial Stipulations

In Section III.16 of the First Partial Stipulation, DEC and the Public Staff agreed to remove the protected federal EDIT from DEC's proposed Rider EDIT and return these amounts to customers through base rates. This change reduces DEC's revenue requirement by $28 million.

In Sections III.A.(2)–(5) of the Second Partial Stipulation, DEC and the Public Staff agreed as follows:

> Total unprotected federal EDIT, North Carolina EDIT, and deferred revenues related to the provisional overcollection of federal income taxes (or the provisional revenues) will be returned to customers through a rider by using a levelized rider calculation methodology as described and set forth in the testimony and exhibits of the Public Staff and will be amortized over a period of five years for total unprotected EDIT and two years for North Carolina EDIT and deferred revenues.

DEC and the Public Staff also reached agreement concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate which may occur during the respective amortization periods as provided in detail in Sections III.A.(6)–III.A.(15) of the Second Partial Stipulation. No intervenor offered any evidence or testimony opposing the EDIT provisions of the DEC and the Public Staff partial stipulations.

CIGFUR Stipulation

In Section IV of the CIGFUR Stipulation, CIGFUR and DEC stipulated that federal unprotected EDIT and the provisional revenues should be refunded to customers on a uniform cents per kWh basis.

Discussion and Conclusions on Return of Tax Act Items to Ratepayers

DEC and the Public Staff have stipulated on the appropriate treatment of the tax issues, as follows:

Tax Act Item	Stipulated Treatment
Protected federal EDIT	Remove from rider and amortize in base rates based on the IRS normalization rules
All unprotected federal EDIT	Levelized rider over five years
Provisional Revenues	Levelized rider over two years
State EDIT	Levelized rider over two years

Tech Customers stated in their post-hearing brief that they favor the provisions of the Second Partial Stipulation that unprotected federal EDIT (together with North Carolina EDIT and deferred revenues related to the provisional over-collection of federal income taxes) be returned to customers through a rider using the levelized rider methodology proposed by the Public Staff over a five-year amortization period, as this is the approach that best balances the need to expeditiously return over collections to ratepayers and DEC's interest in managing its cash flow.

Tech Customers also contended that the longer the period customers are forced to wait for return of the over collections, the longer the forced loan from ratepayers. Tech Customers asserted that returning all unprotected federal EDIT over five years is a reasonable approach that appropriately balances the need to return the over-collections to ratepayers and the need to protect both DEC and ratepayers from the shocks that otherwise would result from significant rate decreases followed by rate hikes.

The AGO argued in its post-hearing brief that DEC should promptly return to ratepayers over $1 billion in EDIT and other over-collected taxes, either as a full offset to a rate increase or as a decrease in rates. The AGO noted that reductions in federal and state corporate income tax rates have lowered operating expenses for utilities and urged the Commission to require DEC to return all of the amounts to ratepayers over no more than two years.

Based upon the record of evidence in this proceeding, the Commission gives significant weight to the DEC and Public Staff First and Second Partial Stipulations concerning the tax issues in this case and finds that it is appropriate to approve those portions of the stipulations. The Commission notes that no intervenor presented testimony disagreeing with the provisions of the settlements in this regard, although the AGO contended in its post-hearing brief that federal unprotected EDIT should be returned within two years instead of five years. However, the Commission is not persuaded that it is appropriate to reject the settlements on this point based on the overall benefits of settling these matters. Further, the Commission gives substantial weight to the testimony of Tech Customers witness Strunk and the information he provided concerning the amortization periods for EDIT adopted by other state commissions across the country. Witness Strunk's testimony shows that a five-year amortization period for EDIT is clearly a reasonable period of time when compared to other state commission decisions. The Commission concludes that the amortization periods stipulated appropriately balance the interests of the ratepayers and DEC.

Discussion and Conclusions on Allocation of EDIT and the Provisional Revenues

The CIGFUR Stipulation provides under Section IV that the parties agree to the refund of unprotected EDIT and the provisional revenues on a uniform cents per kWh basis. In his direct and supplemental testimony, DEC witness Pirro described how he designed the Year 1 rate for the EDIT Rider by taking the rider revenue requirement, aggregating it to the four different rate classes based on how it was allocated in the Company's 2018 per books cost-of-service study, and dividing each class by the applicable test year retail billed sales. Tr. vol. 12, 253-60. Witness Pirro noted during cross-examination that these class-specific EDIT refund rates were in line with the cost allocation method used in this docket. Tr. vol. 13, 27. Witness Pirro testified that he used the revenue requirement from McManeus Exhibit 4 to develop the rates in Pirro Exhibit 9. In his second supplemental testimony, witness Pirro explained that he had revised the EDIT Rider pursuant to the CIGFUR Stipulation to refund EDIT on a uniform cents per kWh basis. Tr. vol. 12, 278. Under this method, one factor would be used for all customers, with the OPT-V class receiving a larger EDIT credit than it paid in EDIT, according to witness Pirro. Tr. vol. 13, 28. Witness Pirro contended that this overpayment of EDIT to one class that was paid in by another is a way to correct subsidization within base rates, but he admitted that base rates and EDIT should be considered separately. *Id.* at 28-29. CIGFUR witness Phillips also agreed that paying EDIT on the uniform cents per kWh basis would reduce any subsidies among classes and stated his belief that it was also done in this manner in the last DEP case. Tr. vol. 22, 146. Public Staff witness Floyd advocated for using witness Pirro's original methodology that returned the EDIT to classes based on how much each class had paid. He said that his proposed method was fairer, as industrial customers would receive more than they had paid if the CIGFUR Stipulation method is used. Tr. vol. 18, 334.

The Commission declines to adopt Section IV of the CIGFUR Stipulation because it will not achieve just and reasonable rates, and therefore is not in the public interest. As the substantial evidence shows, EDIT results from the overpayment of taxes by customers paying rates that include as a portion of the rate charges to cover the utility's anticipated federal and state income taxes. In addition, the amount of those overpayments is determinable from the Company's books and records of customer billing revenues. While different customer classes may have different rates of return (ROR), these RORs are highly dependent on the cost-of-service allocation methodology utilized, as well as the time period during which the cost-of-service study was conducted. As such, subsidy/excess issues should be resolved on the basis of equity between customer classes and their relationship to the overall ROR, not by favoring one class of customers by returning to them more than they paid in EDIT.

While in prior rate cases for DEC and DEP, use of a uniform EDIT rate to allocate state EDIT was agreed to as part of a settlement,[13] no party contested the issue in those cases, and the Commission accepted the settlement terms on state EDIT without making detailed findings of fact as to the appropriateness of a uniform rate. However, in the Commission's recent order in Docket No. E-22, Sub 562, of which the Commission has taken judicial notice in this proceeding, the Commission approved the provision of the stipulation between Dominion Energy North Carolina (DENC) and the Public Staff that the EDIT Rider credit should be allocated to customer classes based upon North Carolina basic (non-fuel) rate revenue annualized reflecting current rates for 2018. Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, *Application of Virginia Electric and Power Co., d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina*, No. E-22, Sub 562, at 60-63 (N.C.U.C. Feb. 24, 2020), *appeal docketed*, No. 477A20 (N.C. Nov. 16, 2020)

With this issue now squarely before the Commission, the Commission finds it inappropriate to address any subsidy issues through reassignment of EDIT. The Commission gives substantial weight to the testimony of Public Staff witness Floyd that returning EDIT credits by customer class is a more equitable method by which to return EDIT. Thus, the Commission concludes that in this case it is inappropriate to refund the unprotected EDIT and provisional revenues to customers through the EDIT rider on a uniform cents per kWh basis and that rather these items should be refunded as a levelized EDIT credit by specific customer-class divided by the adjusted class test year sales.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 49-50

Cost Allocation Methodology

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation and CIGFUR Stipulation; the testimony and exhibits of DEC witnesses Hager and Pirro, Public Staff witness McLawhorn and Floyd, CIGFUR witness Phillips, and NCJC et al. witness Wallach; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Hager testified that the purpose of the cost-of-service study is to align the total costs incurred with jurisdictions and customer classes responsible for the costs and that cost causation is a key component in determining the appropriate assignment of revenues, expenses, and rate base among jurisdictions and customer classes. Witness

[13] In DEC's last rate case, Sub 1146, federal EDIT was deferred until the next rate case or three years, whichever was sooner. In DEP's last rate case, Sub 1142, federal EDIT was not addressed because DEP filed its rate case before the Tax Act was signed into law in December 2017 (and effective January 1, 2018); the DEP Rate Order in Sub 1142 was issued on February 23, 2018.

Hager testified that costs are classified according to their cost-causation characteristics and that these characteristics are typically defined as demand-related, energy-related, or customer-related. The cost-of-service study supporting the Company's proposed rate design in this proceeding allocates the demand-related production and transmission costs based upon a jurisdiction's and customer class' coincident peak responsibility occurring during the summer, otherwise known as the Summer Coincident Peak (SCP) cost allocation methodology.

Witness Hager testified that distribution costs are classified as either demand-related or customer-related. Witness Hager summarized different methodologies for determining the customer-related component of distribution costs and testified that DEC used the "Minimum System" methodology in its cost-of-service study (COSS) for allocating costs to customers. Witness Hager testified that this method is appropriate for allocating customer-related distribution costs. After the customer-related costs are determined, the remainder of distribution costs are classified as demand-related and are allocated based on Non-Coincident Peak (NCP) Demand.

Witness Hager further testified to DEC's use of the MSM and stated that every customer requires some minimum amount of wires, poles, transformers, etc. to receive service; therefore, every customer caused DEC to install some amount of the distribution assets. According to witness Hager, the concept DEC used to develop its Minimum System Study was to consider what distribution assets would be required if every customer had only some minimum level of usage (e.g., one light bulb).

Witness Hager stated that the reason NCP is used for allocating demand-related distribution costs is that distribution facilities serve individual neighborhoods, rural areas, and commercial districts. They do not function as a single integrated system in meeting system peak demand. Instead, the distribution system serving each neighborhood, rural area, or commercial district must be able to meet the peak demand in the area it serves whenever the peak occurs. Witness Hager stated that contribution to NCP is the appropriate measure of determining customers' responsibility for these costs because it best measures the factors that drive investment to support that part of the system.

Witness Hager testified that all costs must be allocated to the appropriate jurisdiction and customer class; if any costs are omitted or remain unallocated then the utility's rates will not allow for full recovery of the Company's operating expenses, including its approved cost of capital. Further, she testified that once all costs and revenues are assigned, the COSS identifies the return on investment the Company has earned for each customer class during the test period. These returns can then be used as a guide in designing rates to provide the Company an opportunity to recover its costs and earn its allowed rate of return.

DEC witness Pirro testified that the base rate increase has been allocated to the rate classes on the basis of rate base. According to witness Pirro, this allocation methodology distributes the increase equitably to the classes while gradually moving each class's deficiency or surplus contribution to return to the retail average rate of return, within a band of reasonableness of +/- 10 percent, if possible.

Public Staff Direct Testimony

The Public Staff recommended using Summer/Winter Peak & Average (SWPA) instead of SCP. Public Staff witness McLawhorn testified that SWPA more accurately and fairly reflects the planning and operation of DEC's production plant to meet the energy needs of its customers.

The Commission ordered the Public Staff to file testimony addressing, as a minimum, SCP, Winter Coincident Peak (WCP), and SWPA cost-of-service methodologies. Witness McLawhorn's testimony includes an analysis of the impact of these cost-of-service methodologies across each of the retail classes of customers. Witness McLawhorn's discussion includes a comparison of class revenue increases for three of the methodologies (SCP, WCP, and SWPA).

Public Staff witness Floyd testified that the Public Staff believes that assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

(1) Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
(2) Maintain a +/-10% "band of reasonableness" for RORs, relative to the overall jurisdictional ROR such that to the extent possible, the class ROR stays within this band of reasonableness following assignment of the proposed revenue changes;
(3) Move each customer class toward parity with the overall jurisdictional ROR; and
(4) Minimize subsidization of customer classes by other customer classes.

Witness Floyd testified that the Company's assignment of its proposed revenue increase does not adhere to the Public Staff's recommended principles outlined above. Further, witness Floyd noted that the Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide a final recommendation on its recommended revenue change. Witness Floyd stated that he will provide the Public Staff's assignment of proposed revenue change at that time.

CIGFUR Direct Testimony

CIGFUR witness Phillips recommended using WCP to reflect the fact that DEC now plans its generating system based on its winter peak demand. Witness Phillips stated that it is appropriate to classify all production investment as demand related. He argued that the capital costs are not a function of the number of kWh generated but are fixed and therefore are properly related to system demands, not to kWh sold. Witness Phillips stated that these costs are fixed in that the necessity of earning a return on the investment, recovering the capital cost (depreciation), and operating the property are related to the existence of the property and not to the number of kWh sold. According to witness Phillips, if sales volumes change these costs are not affected but continue to be incurred, making them fixed or demand-related in nature. He concluded that investment in generation plant is properly classified as a demand-related cost.

Further, witness Phillips contended that if an attempt were made to increase the allocation of investment to one group of customers, on the theory that those customers benefit more than others from the lower energy costs that result from the operation of a base load plant as opposed to a peaking plant, as done in the SWPA method, the analysis should be carried to its logical conclusion. The logical conclusion, according to witness Phillips, would be to fairly and symmetrically allocate energy costs to the group of customers who are forced to bear the higher capital costs allocated to them on a kWh basis. Witness Phillips stated that energy costs allocated to the high load factor class should recognize lower operating costs which result from the higher capital costs of the base load plants. Finally, he stated that the SWPA method fails to allocate lower than average fuel costs to the high load factor customers.

CIGFUR witness Phillips testified that he agrees with DEC's COSS with respect to the allocation of certain distribution facilities. According to witness Phillips, the Public Staff concluded in its March 2019 report that the use of the Minimum System Method for classifying and allocating distribution costs is reasonable.

NCJC et al. Direct Testimony

NCJC et al. witness Wallach provided extensive testimony on the cost-of-service topic. Witness Wallach testified that the Company's COSS misallocates distribution costs partly by misclassifying a portion of such costs as customer-related by relying on a flawed minimum system analysis. Witness Wallach testified that the Company's COSS allocates more distribution plant costs to the residential rate classes than is appropriate under generally accepted cost causation principles. Further, witness Wallach suggested that the Commission should direct DEC to discontinue its use of the MSM and instead rely on the "basic customer method."

In its 2018 DEC Rate Order, the Commission ordered the Public Staff to facilitate discussions with the electric utilities to evaluate and document a basis for continued use of minimum system and to identify specific changes and recommendations as appropriate. The Public Staff submitted its report on March 28, 2019, in Docket No. E-100, Sub 162. In its report the Public Staff concluded that use of the MSM by electric utilities for the purpose of classifying and allocating distribution costs is reasonable for establishing the maximum amount to be recovered in the fixed or basic customer charge.

The basic customer method referenced by witness Wallach accounts for meters, service drops, and certain other related costs. These typically would not include transformer or wires costs. Witness Wallach referred to a report (manual) recently produced by the Regulatory Assistance Project (RAP) entitled *Electric Cost Allocation for* *a New Era*. The report states that "The basic customer method for classification is by far the most equitable solution for the vast majority of utilities."

After the Company determines the customer-related costs using the Minimum System Method, the remainder of distribution costs are classified as demand-related and are allocated based on Non-Coincident Peak Demand. Witness Wallach recommended that the Commission reject the Company's use of the non-coincident peak demand allocator to allocate distribution costs. According to witness Wallach, the non-coincident peak allocator fails to accurately reflect usage patterns of residential customers and causes distribution costs to be over-allocated to the residential classes. Witness Wallach stated that to reasonably account for the effect of load diversity on distribution equipment sizing and cost, demand-related distribution costs should be allocated to rate classes on the basis of each class's diversified peak demand.

DEC Rebuttal Testimony

Witness Hager discussed some of the reasons DEC supports the SCP methodology:

(1) The application of the summer peak load to allocate demand-related production and transmission costs is consistent with the Single Coincident Peak Method identified in the NARUC Electric Utility Costs Allocation Manual;
(2) The predominance of the summer peak in DEC's service territory;
(3) The historical significance of the summer peak in DEC's expansion planning such that the majority of DEC's embedded generation fleet was built in response to summer peaks, thus making it appropriate to allocate these historically incurred costs;
(4) The benefit of a cost allocation methodology that encourages the shifting of usage to off-peak times;
(5) The value of sending consistent pricing signals by using a method that has been approved by this Commission for many years; and
(6) The importance of a consistent cost allocation methodology among DEC's jurisdictions so that the Company does not under- or over-recover its costs.

Further, witness Hager noted that she does not agree with witness McLawhorn's assertion that the SCP methodology only addresses the peak requirement of the capacity expansion planning process and places no value on the plants' requirement to produce energy at any time other than the peak hour. Witness Hager stated that this is not the complete picture. She explained that in developing a cost-of-service study, production costs are classified into demand and energy related costs. According to witness Hager, plant capacity is considered fixed to meet demand and therefore, the cost of plant capacity was assigned to customers on the basis of their contribution to the summer coincident peak. Plant output in terms of kWh generation varies with the system energy requirements; therefore, all variable costs of production are assigned to customers based on their energy usage. Witness Hager commented that in supporting the SWPA methodology, witness McLawhorn fails to acknowledge that the cost-of-service study in this proceeding already classifies over $2 billion of production costs (fuel, purchased power, O&M, etc.) as variable, and allocates these costs to the jurisdiction and customer classes using an energy allocator. Witness Hager stated that the SWPA method would allocate a higher portion of the fixed costs to the higher load factor customers. According to witness Hager, advocates for this method feel this is equitable on the theory that high load factor customers benefit from the lower energy costs that result from the operation of base load plants as opposed to the higher energy costs of peaking plants. However, witness Hager stated that proponents never carry this argument to its logical conclusion. That is, those customers allocated the higher capital costs based on energy usage, should be allocated the lower variable operating costs of those same base load facilities. Witness Hager noted that if the primary theory behind the use of the SWPA allocation methodology is that fixed production plant costs are incurred to meet both capacity and energy requirements, then consideration should also be given to the variable operating costs. She commented that it seems only fair and equitable that high load factor customers should be allocated more of the lower variable energy costs, while low load factor customers should be allocated more of the higher variable energy costs.

Witness Hager testified that she does not agree with witness Phillips' recommended use of the winter peak for the allocation of demand-related production and transmission costs. Witness Hager stated that the generation and transmission asset costs to be recovered in this proceeding were constructed based upon customers' contribution to the summer coincident peak. Therefore, SCP is the appropriate allocation methodology. Witness Hager also expressed concerns with the volatility of the winter peak and the volatility that using a single winter peak could introduce into customer rates.

Witness Hager next turned her attention to Minimum System. She stated that the NARUC cost allocation manual specifically states in the section on allocation of embedded costs that "the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system." She stated that witness Wallach contends that customer connection costs are generally limited to plant and maintenance costs for a service drop and meter, along with meter reading, billing, and other customer-service expenses. Witness Hager noted that witness Wallach quotes Bonbright's Principles of Public Utility Rates to support his argument and noted that the text states that metering and billing expenses are the most obvious examples of customer costs. She commented that witness Wallach failed to mention that the quoted text does not say these are the only costs. Further, witness Hager stated that while it is true that Bonbright recognizes the difficulty of determining the proper allocation for the minimum system costs, he concludes that the exclusion of minimum system costs from demand-related costs is on "much firmer ground" than its exclusion from customer costs. According to witness Hager, Bonbright recognizes that utilities must distribute all costs among the classes of customers in a fully distributed cost analysis. Witness Hager stated that even more important, is the NARUC cost allocation manual that was developed after Bonbright's work. She commented that the cost allocation manual moved from the theoretical world of Bonbright to the reality of utilities' needs to move from development of revenue requirements to rate structures.

Stipulations

The CIGFUR Stipulation provides that prior to the Company's next general rate case the stipulating parties agree to meet to discuss potential cost-of-service methodologies that the Company may recommend for the purpose of allocating production and transmission costs. In addition, in its next general rate case, the Company shall also file the results of a class cost-of-service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes. Further, the stipulation states that in its next general rate case, the Company will adjust its peak demand to remove curtailable/non-firm load, even if it does not call the load. If the Commission approves this adjustment in the Company's next general rate case, then DEC will propose use of this adjustment in its next subsequent rate case. Finally, the stipulation states that in its next three general rate cases DEC agrees to propose to allocate distribution expenses using the minimum system approach; however, if the Commission orders a different approach be used in the current rate case or either of the next two rate cases, DEC may elect to propose the minimum system approach in the next subsequent rate case after the denial, but DEC is not obligated to do so.

The Public Staff Second Partial Stipulation states that for this case only the Public Staff accepts, subject to the conditions in Section IV.B. below, the Company's proposal to calculate and allocate the Company's cost of service based on a SCP methodology. However, the Second Partial Stipulation also states that this provision shall not constitute precedent and shall have no effect on the Rate Design Study proposed by the Public Staff and agreed to by the Company. Further, Section IV.B. states that DEC has based its filing in this docket on the SCP methodology for cost allocation among jurisdictions and among customer classes. However, the stipulating parties agree that prior to the filing of its next general rate case the Company shall undertake an analysis of additional cost-of-service studies subject to the following conditions:

(1) The Company agrees to analyze and develop cost-of-service studies based on each of the following methodologies:

   a. Single Summer Coincident Peak;
   b. Single Winter Coincident Peak;
   c. One that utilizes the four highest monthly system peaks (two monthly peaks in summer and two monthly peaks in winter);
   d. SWPA;
   e. Base Intermediate and Peak (as described in the RAP "Electric Cost Allocation for a New Era" Manual, published January 2020); since the Company's accounting systems do not have the data developed to produce such a study, this method may be analyzed by looking at how it has been used at another utility or with a higher level hypothetical analysis;
   f. One that utilizes the 12 highest monthly system peaks in the test year; and

g. Any other identified relevant methodologies.

(2) Each methodology studied will include an evaluation of the allocation of the functions of utility service (production plant, transmission plant, distribution plant, and customer costs), including an identification of which cost components associated with these functions of utility service are fixed, and which are variable costs of service. The above methodologies only impact production and transmission allocations; however, the cost-of-service studies will show the allocation of all functions. For purposes of these studies, all demand and customer classified costs can be designated as fixed, and all energy classified costs can be designated as variable.

(3) Each methodology studied will include an evaluation of its strengths and weaknesses on both a jurisdictional and class allocation basis.

(4) Included in the studies shall be a discussion of how the allocation of fuel and other variable O&M expenses align with system planning.

(5) The Company shall consult with the Public Staff and any other interested parties throughout the study process.

Further, the Second Partial Stipulation states that the Company will continue to file annual cost-of-service studies based on both the SCP and SWPA methodologies until instructed to do otherwise by the Commission. The Company also agrees that it will not cite Commission approval of the Second Partial Stipulation as support for approval of the SCP methodology in future proceedings.

Discussion and Conclusions

The Commission gives significant weight to the testimony of DEC witness Hager and determines that having the necessary generation and transmission resources to meet the Company’s summer peak, plus an appropriate reserve margin, is an essential planning criterion for the Company’s system. Under cost causation principles all customer classes should share equitably in the fixed production and transmission costs of the system in relation to the demands they place on the system at the peak.

Although the Public Staff has traditionally supported the SWPA methodology, it is not unreasonable for the Public Staff to have agreed to the use of SCP in this proceeding. The Commission gives significant weight to the Public Staff’s Second Partial Stipulation.

Further, the Commission gives significant weight to witness Hager’s testimony concerning the Company’s long history of employing the Minimum System Method and the Method’s alignment with cost causation principles. According to witness Hager’s testimony, after the Company determines the customer-related costs using the MSM, the remainder of distribution costs are classified as demand-related and are allocated based on NCP demand. Witness Wallach recommended that the Commission reject the Company’s use of the NCP demand to allocate distribution costs. The Commission gives little weight to witness Wallach’s argument for this position. The Commission gives more weight to witness Hager’s testimony that NCP is the appropriate measure for determining customers’ responsibility for these costs.

Finally, as discussed more fully later in this Order, the Commission concludes that the provisions of the CIGFUR Stipulation that commit DEC to take specific positions on certain issues in DEC's next several rate cases, such as adjustments to peak demand and use of the minimum system approach, are not relevant to any issue before the Commission in this docket. Under the guidelines set forth in *CUCA I and II*, a nonunanimous stipulation is evidence; however, the Commission can only use relevant evidence as the basis for its decisions. The CIGFUR Stipulation and DEC agreements on future proposals and positions in future rate cases have no relevance in this rate case, and the Commission therefore declines to accept those portions of the CIGFUR Stipulation.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that the greater weight of the evidence shows that the SCP cost-of-service methodology provides the most appropriate methodology to assign fixed production and transmission costs in this proceeding.

The Commission finds and concludes that the Second Partial Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the Second Partial Stipulation is material evidence to be given appropriate weight in this proceeding.

Moreover, as a demonstrated by the opposing testimony between DEC and CIGFUR witnesses, the Commission finds and concludes that the CIGFUR Stipulation is the product of the give-and-take between the parties during their settlement negotiations in an effort to appropriately balance DEC's usage of the SCP and CIGFUR's desire to investigate a different methodology for the sole purpose of apportionment of the change in revenue to the customer classes in the next general rate case. The Commission finds and concludes that the CIGFUR Stipulation was entered into by the parties after substantial discovery and negotiations, and that it represents a proposed negotiated resolution of the matters in dispute in this docket. As a result, the provisions of the CIGFUR Stipulation not otherwise rejected by the Commission are relevant and material evidence to be given appropriate weight in this proceeding.

Moreover, the Commission concludes that the Company's use of the MSM for cost allocation in this proceeding is just and reasonable to all parties in light of all of the evidence presented. Further, the Commission concludes that NCP is the appropriate measure for determining customers' responsibility for demand-related distribution costs after the customer-related costs are determined using the MSM.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 51

Rate Design

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the stipulations between DEC and various parties; the testimony and exhibits of DEC witnesses Pirro, Reed, Huber, and Hager, Public Staff witness Floyd, NCJC et al.

witnesses Wallach and Howat, NCSEA witness Barnes, Harris Teeter witness Bieber, and CUCA witness O'Donnell; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness Pirro testified that when moving rate schedules and riders closer to a more cost-justified basis, it is important to consider the impact upon customers and to employ the principle of "gradualism." Witness Pirro stated that this principle was applied in this proceeding to update price relationships and levelized the percentage change in revenues on participants within the rate class while still moving towards a more equitable pricing structure.

Witness Pirro testified that the Company is not proposing any new peak time pricing rate designs offering real time price signals in this proceeding. Witness Pirro stated, however, that the Company is implementing nine new dynamic pricing pilots effective October 1, 2019 in compliance with the Commission's 2018 DEC Rate.

Witness Pirro testified that the Company's unit cost study indicates it is appropriate to raise the monthly BFC to better reflect all customer-related costs. He indicated that to do otherwise would result in customer cross-subsidization. Witness Pirro stated that the Company would normally propose the BFC for all rate classes be set to recover approximately 50% of the difference between the current rate and the full customer-related unit cost incurred to serve the customer groups. However, according to witness Pirro, the Company decided in this rate case proceeding not to increase the BFC, but rather to leave it at current rates due to past concerns raised by low-income and other advocates with respect to the level of the charge.

Further, witness Pirro stated that the Company is requesting that a collaborative stakeholder process be formed to discuss opportunities to address low-income, fixed-income and low-usage customer concerns. Once the Company has the benefit of that collaborative process, the BFC will be addressed in a future proceeding to properly reflect equitable cost-based rates that provide accurate price signals to customers.

DEC witness Reed adopted the testimony of Marc Arnold and testified regarding the rate design for the Company's 17 outdoor lighting products and services. Witness Reed's testimony expanded on witness Pirro's testimony. Witness Reed stated that the Company re-evaluated the outdoor lighting transition fee charged to customers who move from metal-halide and high-pressure sodium lights to LED (light-emitting diode). According to witness Reed, the Company proposes to lower the transition fees to balance take-rates while protecting the rate class from premature retirement of assets.

Public Staff Direct Testimony

Public Staff witness Floyd testified that the Company made very few modifications to any of its rate schedules other than to increase individual rate elements within each schedule to accomplish the revenue increase assigned to the rate class itself. However, witness Floyd stated that notwithstanding his testimony highlighting the status quo nature of the Company's rate schedules, he is generally supportive of the few proposed changes to rate schedules and service regulations as discussed by witnesses Pirro and Reed. Witness Floyd noted that the Company proposed changes to its lighting rate schedules, Rider MRM, and certain fees in its service regulations.

Witness Floyd testified that the Company has not utilized AMI data to develop new rate designs or inform the existing rate designs. Witness Floyd referenced his testimony in the Sub 1146 proceeding where he highlighted the Company's commitment to exploring and developing new rate designs once smart meters were fully deployed and data from those meters became available. According to witness Floyd, that time has arrived. He stated that the Company should begin incorporating AMI data into its load research efforts supporting both rate design and integrated resource planning. He recommended that the Commission order a comprehensive rate design study and suggested rate design questions to be addressed.

Witness Floyd testified that is appropriate for the Company to begin working on new EV rate designs now and to discuss those designs with stakeholders as they are considered and developed. He proposed that the Commission require DEC to develop and propose EV rate designs as part of the larger rate design study recommended.

Witness Floyd stated that the Public Staff does not object to the Company's proposal to leave the BFC at current levels for purposes of this proceeding.

Finally, witness Floyd testified that the Public Staff supports convening a stakeholder process to address affordability issues, including the appropriate amount of the BFC.

NCJC et al. Direct Testimony

Witness Wallach recommended that the Company's request to maintain the residential BFC at its current rate of $14.00 per bill be denied. He instead recommended that the residential BFC be reduced to $11.15 per bill. Witness Wallach testified that it is unreasonable for DEC to recover costs through the residential BFC that were classified as "customer-related" using a minimum-system analysis. Further, witness Wallach noted that once the excess uncollectible and customer-related distribution costs from the minimum-system analysis are removed, he estimates that a residential BFC of $11.15 would recover the truly customer-related costs of meters, service drops, and customer services allocated to the residential rate classes. Witness Wallach stated that to the extent that usage-driven costs are recovered through the fixed customer charge rather than through the volumetric energy rate, residential customers with below-average usage bear a disproportionate share of usage-driven costs and consequently subsidize customers with above-average usage. Witness Wallach attempted to characterize this subsidization in his testimony.

Witness Howat also recommended that the Commission reject the $14.00 residential BFC and approve the $11.15 BFC proposed by witness Wallach.

NCSEA Direct Testimony

NCSEA witness Barnes provided extensive testimony on his proposal that the Commission direct DEC to establish EV specific rates for both home charging and commercial charging applications. Witness Barnes recommended that the Commission direct DEC to file separate, targeted EV-specific tariffs for both residential and nonresidential dedicated EV charging, reflecting the core characteristics discussed in his testimony. He stated that this should occur within 60 days of the order in this rate case.

Further, witness Barnes recommended that the Commission establish an investigatory docket to receive further information and permit further discussion of EV-specific rates, lessons learned, and potential refinements.

Harris Teeter Direct Testimony

Witness Bieber recommended modifications to the proposed OPT-VSS rate design that he opined would improve the alignment between the rate components and the underlying costs while employing the principle of gradualism and mitigating intra-class rate impacts. This rate schedule is a time of use rate class that provides separate rates for customers of varying size and delivery voltage. Witness Bieber noted that according to witness Pirro, the Company designed its commercial and industrial rates utilizing a uniform percentage increase method, which seeks to allocate the additional cost recovery across the various components of each schedule. According to witness Bieber, witness Pirro claims that this method maintains the overall structure of the rate without distortion relative to the historical rate design. Witness Bieber stated that he fundamentally disagrees with the proposed use of a uniform percentage increase method because it is not consistent with the cost causation drivers. Further, DEC proposes to increase the rate OPT-VSS energy charges by more than 9%, while according to the Company’s own unit cost-of-service study, the proposed energy-related costs for rate OPT-VSS increased by less than 2%. Witness Bieber testified that DEC’s proposed rate design under-recovers the demand-related charges while over-recovering the energy-related charges.

CUCA Direct Testimony

CUCA witness O’Donnell testified that the Commission should require DEC to immediately convene meetings with the Company’s large customers to ascertain and offer new interruptible rates to its large customers no later than January 1, 2021.

DEC Rebuttal Testimony

DEC witness Huber stated that changes in customer interests, political and regulatory priorities, and increasing adoption of new technologies demand a rethinking of DEC’s rate designs. He agreed that the Company should conduct a comprehensive rate design study. Further, witness Huber proposed that DEC complete the study by the end of the second quarter of 2021.

Witness Huber stated that the Company cannot cost-effectively implement any rate design changes until the new Customer Connect billing system is in use. Because it is more cost-effective to implement new rates concurrently with the new billing system, DEC strongly favors utilizing the time prior to implementation to analyze data, convene stakeholders, and refine its proposals. According to witness Huber, Customer Connect is scheduled to be implemented for DEC in the spring of 2021. Once the new Customer Connect system is fully deployed and post-deployment stabilization is achieved approximately six months later, the Company will be ready to begin implementing new rate designs.

Further, witness Huber stated that increasing the adoption of EVs is a state policy goal that could provide significant system benefits and a study of rate designs that facilitates the adoption of electric vehicles will be a part of any comprehensive rate design study.

Witness Pirro noted that the Company's Rate Schedule OPT-V is well received and very popular among the commercial and industrial customer base as it offers variation in pricing to incent changes in usage behavior. According to witness Pirro, the Company, in Docket No. E-7, Sub 1026, filed DEC's OPT rate schedule criteria. The redesign of OPT was fully vetted and agreed upon by both CUCA and CIGFUR and approved by the Commission. The Company diligently pursued a fair and equitable cost-based resolution, as all subsidy/excess revenues were eliminated within the OPT class. Witness Pirro stated that the approved redesign ultimately focused the increase to the on-peak portion of the rate in order to send a stronger price signal for off-peak usage.

Witness Pirro stated that he does not agree with proposed changes to the OPT-V rates. He commented that the witnesses appear to be supportive of cost-based rate design. However, witness Pirro stated that the witnesses miss an important translation between cost of service and rate design. According to witness Pirro, rate design needs to look at the rate structure and provide balance (customer, demand, and energy) to provide an accurate price signal to customers. The rate designer's task is to design a rate that best mimics the cost of serving customers across a range of usage without all cost elements being strictly defined by the rate structure. Further, witness Pirro noted that an industry method used to accomplish this is to allocate a portion of demand costs to be included in the energy charge. He stated that the simplistic notion that all demand costs be included in a demand charge and all energy costs be included in an energy charge would essentially invalidate most of the rate structures in the industry across the country. Further, according to witness Pirro, if rates increase, more and more costs would be unjustifiably borne by the lower load factor customers in the group with the methods advocated by the intervenors. Finally witness Pirro stated that this would decrease their competitiveness and cause real economic harm, while their higher load factor counterparts enjoy the results of a mispriced product.

Witness Pirro stated that he disagrees with the intervenors that allege costs identified by the Minimum System Methodology are not customer costs and should be excluded from the BFC. He noted that the Company's COSS indicate that these costs are customer costs and, therefore, the BFC was designed to recover them. Further, witness Pirro commented that the primary residential rate schedule does not have a demand component; rather, it only has a BFC and a volumetric per kWh charge. He testified that it would be inappropriate to shift costs currently included in the BFC to a volumetric rate. He stated that failing to properly recover customer-related costs via a fixed monthly charge would provide an inappropriate price signal to customers and would fail to adequately reflect cost causation. Shifting customer-related costs to a volumetric per kWh rate further exacerbates this concern and overcompensates energy efficiency and distributed generation for the cost avoided by their actions, thereby skewing the market for such measures.

Witness Hager stated in her rebuttal testimony that the Public Staff made several observations regarding setting the BFC. For example, she noted that the Public Staff differentiates between the considerations in a COSS and Rate Design, the latter of which the Public Staff states should take additional things into consideration such as policy objectives and appropriate price signals. Witness Hager testified that similar to the Public Staff, she believes it is appropriate to keep a COSS free of biases and focus on cost causation.

Stipulations

The CIGFUR Stipulation states that should the Company independently undertake or should the Commission order a comprehensive rate design process prior to the Company's next general rate case, the Company agrees to explore the following: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's HLF rate, (2) allowing customers to move existing load to the existing HP Hourly Pricing rate, and (3) an emergency demand response program similar to Southern California Edison's Time-of-Use Base Interruptible Program (TOU-BIP) tariff. If there is mutual agreement between CIGFUR and the Company on the terms of any of the above referenced rates and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, the Company agrees to file said rates with the Commission for approval in its next rate case filing.

Further the CIGFUR Stipulation states in the event that the Commission does not order or DEC does not independently undertake a comprehensive rate design process prior to its next general rate case, then prior to its next general rate case the Company agrees to consult with CIGFUR on: (1) a rate schedule targeted at high load users similar to Duke Energy Indiana's HLF rate, (2) allowing customers to move existing load to the existing HP-Hourly Pricing rate, and (3) an emergency demand response program similar to Southern California Edison's TOU-BIP tariff. If there is mutual agreement between CIGFUR and the Company on the terms of discussed rates and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, the Company agrees to file said rates with the Commission for approval in its next rate case filing.

The Commercial Group Stipulation as well as the Harris Teeter Stipulation state that the Commercial Group and DEC agree that the OPT-VSS off-peak energy charge shall be set at 3.0222 cents/kwh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. The demand charges for the OPT-VSS rate schedule shall be adjusted by the amount necessary to recover the final OPT-VSS revenue target. Both stipulations state that GIP costs allocated to OPT-V customers shall be recovered via OPT-V demand charges.

The Public Staff Second Partial Stipulation states that:

(1) The Company agrees that any proposed revenue change will be apportioned to the customer classes such that:
   a. With the exception of DEC's lighting customer class where the ROR falls significantly below the overall North Carolina retail ROR, any revenue increase assigned to any customer class is limited to no more than two percentage points greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;
   b. Class RORs are maintained within a band of reasonableness of +/- 10% relative to the overall North Carolina retail ROR; for class RORs currently above the band of reasonableness, the Company will gradually move class RORs closer to the band of reasonableness;
   c. All class RORs move closer to parity with the North Carolina retail ROR;
   d. Subsidization among the customer classes is minimized.

(2) The stipulating parties agree that the proposed modifications to the Company's rate schedules are reasonable for purposes of this proceeding.

(3) The stipulating parties agree that the Commission should order a comprehensive rate design study.

Discussion and Conclusions

The Commission concludes that the Company's proposed portfolio of rate designs as modified by this Order, specifically including the rate design provisions outlined in §§ IV.C and D of the Public Staff Second Partial Stipulation, are just and reasonable for purposes of this proceeding. Nonetheless, as the Company and customers adopt new technologies and uses of the electric system change, rate design must evolve in order to maximize the efficiency and effectiveness of these new technologies and ensure usage of the electric system that is consistent with the public interest. The Commission recognizes the impact the results of a comprehensive rate study may have on future utility services, customers, and the economy of the State. That said, the Commission concludes that it is in the public interest to direct the Company to conduct a comprehensive rate design study (Rate Design Study) as outlined in § IV.E of the Second Partial Stipulation and further described in the testimony of witnesses Floyd and Huber, and as expanded upon herein. The Public Staff invited Commission guidance on scope and timeline of the study but emphasized that some flexibility is necessary to ensure robust discussion amongst stakeholders. Tr. vol. 18, 287. The Company agreed that broad stakeholder engagement is a necessary component of the comprehensive rate design process. Tr. vol. 13, 42. Based on the evidence in the record, the Commission provides the following guidance.

With respect to scope, the Rate Design Study should address, at a minimum, those rate design questions set forth in § IV.E(1)–(6) of the Second Partial Stipulation, including firm and non-firm utility services, various types of end uses (EVs, microgrids, energy storage, and DERs), the formats of future rate schedules, marginal cost versus average cost rate designs and pricing, unbundling of average rates into the various functions of utility services, and socialization of costs versus categorization of specific costs. The Rate Design Study should include but not be limited to these topics. The Commission is persuaded that in depth evaluation, debate, and discussion by and among stakeholders regarding cost to serve, rate design, and making the most efficient use of the electric system is necessary to achieve results that are in the public interest, and the Commission directs the Company to ensure that all necessary and appropriate topics are considered, to this end. For example, the Commission notes that § V.E of the CIGFUR Stipulation includes commitments by the Company in the event that the Commission directs the Company to undertake a comprehensive rate design study. Notwithstanding the foregoing, the Commission directs the Company and all parties that participate in the Rate Design Study to work cooperatively, productively, and efficiently to ensure that resources are efficiently expended on this endeavor and that the outcome aligns with the public interest.

In response to Commission questions, witness Huber confirmed that the issue of the rates and charges for services for net metering customers would be a part of the Rate Design Study. Tr. vol. 13, 94, 112-13. Thus, the Commission anticipates and expects that net metering will be considered in the Rate Design Study and that consistent with N.C.G.S. § 62-126.4(b), the Rate Design Study will address the costs and benefits of customer-sited generation.

With respect to the recommendations of NCSEA witness Barnes regarding EV charging rates, the Commission determines that the development of such rates is most appropriately evaluated in the context of the Rate Design Study as opposed to in a separate proceeding. Thus, the Commission directs the Company to include the investigation of EV rate designs in the Rate Design Study.

Similarly, with respect to the recommendations of CUCA regarding the development of interruptible rates for large industrial customers, the Commission concludes that the development of such rates is most appropriately evaluated in the context of the Rate Design Study.

Public Staff witness Floyd testified as to the relationship between cost-of-service studies and rate design. He testified that while rate design does not strictly follow cost-of-service studies in every instance, cost-of-service studies most definitely inform rate design. Tr. vol. 18, 341. The Public Staff takes the position that a cost-of-service study aligned with the current rate design portfolio of electric tariffs should be the beginning of the Rate Design Study. *Id*. The Public Staff envisions that the Rate Design Study would take the existing portfolio of rate schedules, including all current principles and policies that inform the current components, and calculate rates as close to a purely cost-based approach as possible. *Id*. The Public Staff envisions the following process: (1) conducting a load study using DEC's new AMI network; (2) ascertaining, through use of the load data, the distinguishing characteristics of customers and customer classes that would serve as the basis for a cost-of-service structure; and (3) building rate designs that allow customers some choice and flexibility in how they want to use energy, and develop new rate designs using the costs to serve those customers. Tr. vol. 18, 341-42. Public Staff witness Floyd testified that this exercise would provide insight and information to the Commission as to costs and impacts on customers of the various rate designs considered. The Commission agrees with the Public Staff that the exercise, as described by witness Floyd, should provide the Commission with critical information regarding load characteristics of customers and customer classes, associated costs, and impacts to customers that could be used to inform future decisions of the Commission. Thus, the Commission directs the Company to undertake the Rate Design Study through the process envisioned by witness Floyd.

Further, as recommended by Public Staff witness Floyd, the Commission finds that the Rate Design Study should: (1) include an analysis of each existing rate schedule to determine whether the schedule remains pertinent to current utility service, including whether the schedule should remain the same, be modified, or be replaced; (2) address the potential for new schedules to address the changes affecting utility service; (3) provide more rate design choices for customers; and (4) explore the feasibility of consolidating the rates offered by DEC and DEP. Tr. vol. 18, 283.

Company witness Huber indicated that the Company is open to a third-party facilitator for the stakeholder portion of the Rate Design Study. Tr. vol. 13, 42. The Commission agrees that the use of an independent facilitator would be appropriate and, thus, directs the Company to engage a third party for this purpose.

All parties to the rate case proceeding should be afforded the opportunity to participate as stakeholders in the Rate Design Study. The Commission directs the Company to initiate the Rate Design Study with stakeholders no later than 30 days following the issuance of this Order.

With respect to timing, as indicated by witness Huber's testimony that the Rate Design Study will yield a detailed "roadmap" within a year, the Commission directs the Company to file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of this Order. In addition, the Commission directs the Company to file quarterly status reports in the instant docket, providing, in detail, the work of the Rate Design Study participants over the previous quarter, including objectives achieved, and anticipated work to be undertaken going forward, including objectives to be achieved.

Finally, the Commission recognizes that the Rate Design Study and the affordability collaborative described hereinafter are separate but parallel efforts. To the extent the parties participating in the affordability collaborative recommend the design of new rates to offer to low-income customers, the parties should present those recommendations to the rate design study participants for consideration. Additionally, the Commission does not intend for the stakeholder processes for affordability and the Rate Design Study to be mutually exclusive or contingent upon the completion of either stakeholder process.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 52–54

Affordability

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the stipulations between DEC and various parties; the testimony and exhibits of DEC witnesses De May and Pirro, Public Staff witness Floyd, NCJC et al. witness Howat, and CBD/AV witness McIlmoil; and the entire record in this proceeding.

Summary of the Evidence

DEC Direct Testimony

DEC witness De May testified that DEC is committed to helping customers who struggle to pay for basic needs with programs and options to assist them during times of financial hardship. He outlined several existing programs that have helped many of their customers in this regard. Witness De May stated that DEC is convinced that more low-income energy assistance programs can be offered to aid customers in need of support. Further, he stated that stakeholder engagement is necessary to adequately develop an appropriate suite of effective options for the Commission to consider for approval. The Company requested that the Commission direct the Company to host, and the Public Staff to participate in, a collaborative workshop with interested stakeholders to address the establishment of new low-income programs.

Witness Pirro testified that the Company proposes to increase the monthly discount applicable to eligible customers taking service under Rate RS and Rate RE, receiving Supplemental Security Income (SSI) under the program administered by the Social Security Administration and who are blind, disabled, or 65 years of age or over. The discount was authorized by the Commission on August 31, 1978. The Company proposed to increase the maximum discount by approximately 10% to 11% to $3.25 for schedule RS and $3.14 for RE, per month.

Public Staff Direct Testimony

The Commission’s January 22, 2020 order in this docket directed the Public Staff to “investigate DEC’s analysis of affordability of electricity within its service territory as well as programs available to DEC’s customers that address affordability with a particular focus on residential energy customers." In the order the Commission directed the Public Staff to address the following issues:

(1) An overview of Lifeline Rates and whether this approach would be appropriate for North Carolina;
(2) The applicability, design, and effectiveness of the Company's SSI discount;
(3) A comparison of the SSI discount to other tariffs available to customers that address affordability issues;
(4) An overview of similar affordability tariffs or plans available by the other affiliates of DEC; and
(5) The merits of using a "minimum bill" concept in lieu of a fixed customer charge.

Public Staff witness Floyd addressed each of these issues in his testimony. Consistent with the Company's request as discussed by witness De May, witness Floyd stated that the Commission should order the convening of a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

NCJC et al. Direct Testimony

NCJC et al. witness Howat provided extensive testimony on issues related to affordability of electric service for DEC's lower-income residential customers and discussed programs and policies designed to mitigate affordability challenges faced by those customers. Witness Howat outlined policy objectives and program design elements featured in effective programs, provided brief descriptions of a sampling of investor-owned utility bill affordability programs operating in the U.S., and recommended that the Commission initiate a process culminating in approval of funding and implementation of enhanced low-income bill payment assistance programming and low-income residential energy-efficiency programming in the DEC service territory. Finally, witness Howat recommended that the Commission direct DEC to expand the Helping Home Fund and consider shifting it from a shareholder- to a ratepayer-funded program.

CBD/AV Direct Testimony

CBD/AV witness McIlmoil provided extensive testimony addressing the impacts that DEC's proposal to increase rates will have on low-income households, specifically on the home energy cost burden those households experience. Witness McIlmoil recommended that the increase in residential electric bills proposed in the present case, in the first year and over the following four years, must not only be considered by itself but also within the context of DEC's intention to shift more costs onto the residential class while increasing the monthly BFC. In that regard witness McIlmoil recommended that the Commission consider all of these factors, especially in light of its mandate to consider changing economic conditions and customers' ability to afford rate increases.

Further, witness McIlmoil testified that in addition to accepting and adopting his recommendations, that the Commission should encourage DEC to recognize and accept the definition and use of the phrase “energy burden,” and make a more concerted and immediate effort to invest in low-income energy efficiency and demand-side management programs at a scale of investment sufficient to meet the scale of the energy problem among its low-income customers.

DEC Rebuttal Testimony

DEC witness Pirro stated that the Company is mindful of the impact of any rate increase on customers, particularly low-income customers; however, the Company does not design rates based on income, but rather applies cost causation principles to the extent practical. Further witness Pirro stated that there are other means of addressing the financial needs of low-income customers, such as Company, state, and local programs, which are more effective than biasing the rate design. However, witness De May stated that the Company supports a dialogue on ways to mitigate electricity costs for low-income customers. He stated that the Company looks forward to the opportunity to engage with its interested stakeholders in a collaborative workshop to address this important issue.

Stipulations

The NCSEA/NCJC et al. Stipulation states that the Company agrees to provide, in conjunction with the concurrent commitment of Duke Energy Progress, LLC (DEP), an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million).

Further, the NCSEA/NCJC et al. Stipulation states that within six months of the effective date of the stipulation, in addition to the low-income collaborative proposed by DEC, the stipulating parties agree to collaborate to design additional low-income DSM/EE program pilots to present to the DEC and DEP DSM/EE Collaborative for consideration.

The Public Staff Second Partial Stipulation states that the stipulating parties agree that the Commission should order the Company to convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. The stipulating parties propose one year for this process.

DEC witness De May discussed in his second settlement testimony how the partial settlement balances the Company’s need for rate relief with the impact of such rate relief on customers. Witness De May stated that he attended public hearings held by the Commission in this matter and personally heard from many customers who are concerned about the impacts of any rate increase on their families and businesses. Witness De May stated that DEC is very mindful of these concerns. Further, he stated, in light of the current economic conditions of many customers due to the COVID-19 pandemic, the Company believes that the concessions the Company has made in the Second Partial Settlement fairly balance the needs of customers with the Company’s need to recover substantial investments made in order to continue to comply with regulatory requirements and safely provide high quality electric service to customers. Witness De May stated that the

Company agreed to make an annual $2.5 million shareholder contribution to the Share the Warmth Program in 2021 and 2022, for a total contribution of $5 million.

Discussion and Conclusions

The Commission gives significant weight to the testimony of Public Staff witness Floyd addressing the affordability issues raised in the Commission's January 22, 2020 order.

In addition, the Commission gives weight to the extensive testimony of NCJC et al. witness Howat concerning affordability. Witness Howat's comments on the need for low-income affordability programs, policy objectives and program design elements featured in effective programs, as well as descriptions of investor-owned utility bill affordability programs are most informative.

The Commission also gives weight to the information provided in the late-filed exhibits of NCJC et al. which are sufficiently responsive to Commission questions posed during the hearing.

The Commission gives significant weight to the provisions of the NCSEA/NCJC et al. Stipulation and the Public Staff's Second Partial Stipulation discussed above, each of which recommend a stakeholder process that is tasked with addressing affordability issues for low-income residential customers.

Based on the evidence in this proceeding, including the stipulations, the Commission finds and concludes that it is appropriate for the Company to convene a stakeholder process (collaborative) that is tasked with addressing affordability issues for low-income residential customers, with a timeline for the process, including deadlines for periodic reporting and filing recommendations to the Commission. Both Company and intervenor witnesses highlighted the need for direction from the Commission in establishing the goals and parameters of the stakeholder process. The Commission takes note of the fact that Company witness De May attended the public witness hearings held in this proceeding and accepts his attendance as an indication of the Company's commitment to its customers in this endeavor.

Starting with and building upon witness Floyd's framework, the Commission directs that the collaborative should as part of its work:

(1) Prepare an assessment of current affordability challenges facing residential customers. The assessment should:

a. Provide an analysis of demographics of residential customers, including number of members per household, types of households (single family or multi-family), the age and racial makeup of households, household income data, and other data that would describe the types of residential customers the Company now serves. To the extent demographics vary significantly across the

Company's service area, provide additional analysis of these demographic clusters.

b. Estimate the number of customers who live in households with incomes at or less than 150% of the federal poverty guidelines (FPG), and those whose incomes are at or less than 200% of the FPG.

c. For the different demographic groups identified as part of a. and b., provide an analysis of patterns and trends concerning energy usage, disconnections for nonpayment, payment delinquency histories, and account writeoffs due to uncollectibility.

(2) Develop suggested metrics or definitions for "affordability" in the context of the Company's provision of service in its North Carolina service territory and explore trends in affordability. Questions to be answered include but should not be limited to:

a. How is "affordability" defined and applied in other jurisdictions particularly for those with similar legal and regulatory frameworks, i.e., vertically integrated investor-owned utilities?

b. What criteria (both qualitative and quantitative) should the Commission consider when determining who would be eligible for different types of affordability programs?

(3) Investigate the strengths and weaknesses of existing rates, rate design, billing practices, customer assistance programs and energy efficiency programs in addressing affordability. Questions that should be addressed include:

a. What defines a "successful program" and what metrics should be monitored and presented that show the impact of programs on addressing or mitigating affordability challenges?

b. What percentage of residential customers are eligible for each existing program and what percentage of eligible customers enroll in and/or take advantage of these programs?

c. What is the impact of existing programs on the energy burden for enrolled customers?

d. Should existing programs be maintained, replaced or terminated? If maintained, should any changes be made to improve results? If programs are replaced, what would replace them?

e. Are the following programs, in addition to any others agreed upon by the collaborative, appropriate for implementation in North Carolina and, if so, what statutory or regulatory changes are necessary to permit implementation: (1) minimum bill concepts as a substitute for fixed monthly charges; (2) income-based rate plans, such as Ohio's percentage of income payment plan; (3) segmentation of the existing residential rate class to take into account different levels of usage; (4) expanding eligibility for DEC's current SSI-based program to include additional groups of ratepayers; and (5) the inclusion of a specific component in rates to be used to fund supplemental support programs. Priority should be given to identifying affordability programs that comply with the current statutory framework, however the collaborative may describe high potential programs that have been successful in other jurisdictions but which would require statutory changes for implementation in North Carolina.

f. How do specific programs addressing affordability affect cost-causation and allowance of costs among classes?

g. How does cost-of-service allocation affect rate design and affordability of rates?

h. What, if any, practices and regulatory provisions related to disconnections for nonpayment should be modified or revised?

i. What existing utility and external funding sources are available to address affordability? Estimate the level of resources that would be required to serve additional customers

j. What are the opportunities (and challenges) of the utilities working with other agencies and organizations to collaborate and coordinate delivery of programs that affect affordability concerns?

The Commission does not intend this list of topics to be exhaustive or limiting in any manner. The Commission will look to the stakeholder process to provide information, guidance, and recommendations on the existing programs, future programs, and the mechanisms for funding that would be needed.

Within 90 days of the date of this Order, the Company and the Public Staff shall convene a collaborative for interested stakeholders to address the affordability of electric service for low-income customers. The collaborative should be facilitated by a third party with experience in affordability issues. The Company should solicit from interested stakeholders the names of individuals that should be invited to participate in the collaborative. As an example, interested stakeholders could include the Public Staff, the AGO, NCJC, NCHC, NAACP, AARP, Legal Aid of North Carolina, etc. Stakeholder groups that want to be directly represented in the collaborative's work should contact the Public Staff to signal their interest in participating. A final list of participants including support for their participation should be submitted to the Commission. After reviewing this recommended list, the Commission will either accept or suggest modifications to the list.

Within 180 days of the date of this order, the Company and the Public Staff shall file with the Commission a report (individually or jointly) that briefly summarizes progress to-date including any noteworthy interim findings or recommendations. Thereafter, progress reports are to be filed quarterly.

Within 12 months of the date of the first workshop, the Company and the Public Staff are required to file a joint final report with the Commission outlining the feedback and recommendations obtained in the collaborative, including any new programs, rate schedules, and funding mechanisms that have wide or consensus support of stakeholders. In addition to the report identifying stakeholder consensus, it should also identify programs that were studied and supported by a number of stakeholders but may not have reached full consensus.

The Commission will then issue a procedural order allowing for the public and interested parties to comment on the joint final report.

The collaborative recommendations should include a mix of proposed programs that can be implemented in the near term and those that will require additional lead time to implement due to complexities. For example, the Commission anticipates/expects concrete proposals that (a) include both elements of rate design and programs that can be layered on top of existing or future rate plans, (b) can be implemented by petition and proceedings prior to the next general rate case because the proposals do not include rate design changes, (c) will be proposed by DEC for consideration in its next general rate case, and (d) have been fully costed out.

The Commission does not intend the stakeholder processes for affordability and comprehensive rate design to be mutually exclusive or contingent upon the completion of either stakeholder process. If consensus is achieved on particular issues surrounding affordability, proposals may be brought forward for consideration as soon as practicable. Given the overlapping nature of the work of the energy efficiency collaborative, the proposed rate study effort, and the affordability collaborative, those working on the three efforts should, to the extent possible, stay abreast of and consider the ongoing work of the separate teams as they each carry out their work. At a minimum, each progress report should include a section that describes the major interactions and connections between the affordability collaborative and the rate study and energy efficiency stakeholder groups. The Commission recommends that to the extent appropriate, interim material produced from each of the three groups be made available to each of the other groups. The Commission recommends holding at least one in person or virtual joint meeting of the three groups to specifically identify and discuss key areas of concern.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 55–61

Storm Costs

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff First Partial Stipulation; the testimony and exhibits of DEC witnesses De May, Jackson, and McManeus and Public Staff witness Boswell; and the entire record in this proceeding.

Summary of the Evidence

In its Storm Cost Petition DEC sought approval from the Commission to defer certain storm repair costs incurred by the Company in responding to Hurricanes Florence and Michael and Winter Storm Diego.

In its Application DEC proposed to consolidate its Storm Cost Petition with the rate case and to recover its Storm Costs through a revision to its base rates. In the testimony of Company witness De May, however, the Company linked its Storm Costs recovery request to the passage of Senate Bill 559, An Act to Permit Financing for Certain Storm Recovery Costs (SB 559), and indicated that if that pending legislation were enacted by the General Assembly the Company would seek recovery of its Storm Costs through a securitization filing instead of in revised base rates.

In his direct testimony Company witness Jackson detailed DEC's general storm response and recovery systems and procedures. Tr. vol. 11, 754-69. He described how DEC plans for, prepares to respond, and ultimately does respond to major storm events impacting its system. Witness Jackson also testified to the details of the three storms impacting DEC's system in 2018, recovery for which was being sought in this proceeding. Those three storms were: Hurricanes Florence, Hurricane Michael, and Winter Storm Diego. Tr. vol. 11, 769-77. Company witness Jackson described the Company's extensive responses to those storms and the capital investments and O&M expense associated with those responses. *Id.* at 777-91. Witness Jackson testified that he believed DEC's response to the storms, including its restoration efforts, was reasonable and prudent and resulted in the restoration of power to DEC's impacted customers as quickly and safely as was reasonably possible. *Id.*

In her direct testimony DEC witness Jane McManeus proposed that the Commission allow DEC to recover the incremental cost in excess of normal storm expenses, including a return on the unrecovered balance. DEC witness McManeus proposed to begin amortization of the costs when proposed new base rates became effective and to include a return on the deferred balance through the end of the proposed eight-year amortization period.

In its Application DEC's Storm Costs, which were projected through July 31, 2020, totaled approximately $193.4 million, which consisted of approximately $168.4 million in actually incurred or projected storm response O&M costs and approximately $25.0 million in deferred depreciation expense and carrying costs (calculated using DEC's approved weighted average cost of capital) on its actual incurred storm response costs. Witness McManeus' Second Supplemental Direct Testimony and Schedules included updated actual amounts of DEC's Storm Costs totaling $213.1 million, consisting of $169.8 million in actually incurred or projected storm response O&M costs, $18.6 million in capital investments, and $24.7 million in carrying costs (calculated using the Company's approved weighted average cost of capital through July 31, 2020).

The only other witness to offer testimony on storm response and recovery costs in this proceeding was Public Staff witness Boswell. Witness Boswell, in her direct testimony, indicated that the Public Staff had reviewed the Storm Costs sought to be recovered in this proceeding and had concluded that they were prudently incurred. Tr. vol. 17, 259. Witness Boswell also indicated that she had made an accounting adjustment to remove the Storm Costs from the rate relief requested in this docket on the basis of Company witness De May's testimony that if the (then pending) storm cost securitization legislation was enacted DEC would seek to recover its Storm Costs through the alternative securitization mechanism provided by that legislation. *Id*. at 258. Finally, Public Staff witness Boswell adjusted DEC's revenue request to allow for a ten-year normalization of future storm costs that are not sufficient to support a separate securitization filing. *Id*. at 259.

In rebuttal testimony Company witness De May testified that SB 559 had been passed by the General Assembly and that the Company looked forward to pursuing recovery of its Storm Costs through a separate securitization filing, but that the Company believed that a determination of the reasonableness and prudence of its Storm Costs should be preserved in the general rate case for determination by the Commission. Tr. vol. 11, 875-76.

On March 25, 2020, DEC and the Public Staff filed the First Partial Stipulation in this proceeding in which these parties reached agreement as to the proper resolution of several pending issues in the general rate case proceeding, including the treatment of Storm Costs. In the First Partial Stipulation DEC accepted the "Public Staff's adjustments to remove the capital investments and O&M costs associated with the Storms and to reflect a 10-year normalized level of storm expense for storms that would not otherwise be large enough for the Company to securitize." First Partial Stipulation, § III.1. As agreed in the First Partial Stipulation, DEC removed the Storm Costs and associated capital investments from the rate case to pursue securitization.

DEC and the Public Staff also agreed to a presumptive filing schedule and filing parameters for DEC's securitization filing for its Storm Costs and reserved their respective rights if such filing was not made by the Company. *Id.* at 7-9. Finally, the parties agreed that a storm cost recovery rider should be established for DEC with an initial balance of $0. *Id.* at 9. More specifically regarding the filing schedule, DEC agreed to file a petition for a financing order pursuant to N.C.G.S. § 62-172 no later than 120 days from the issuance of an order by the Commission in this rate case in which the Commission makes findings and conclusions regarding the Storm Costs and the First Partial Stipulation, unless a party in the rate case appeals the Commission's order as it relates to the Storm Costs or the provisions of the First Partial Stipulation related to the Storm Costs and securitization. If an appeal is filed, the 120-day limit shall be suspended until the Commission's decision is affirmed, or if not affirmed, until the issuance of a Commission Order on remand following the decision on the appeal, unless the Company chooses before that time to pursue recovery as further described below, in which case the original 120-day limit shall be deemed to have applied. Should DEC fail to file a petition within the time period specified in this paragraph, DEC and the Public Staff agreed that in any subsequent ratemaking proceeding held to provide for recovery of the Storm Costs, the parties reserve the right to assert their respective positions regarding the appropriate ratemaking treatment of the Storm Costs. *Id.,* § III.2.

DEC filed its Storm Costs securitization financing petition with the Commission on October 26, 2020, in Docket No. E-7, Sub 1243.

With regard to the parameters that would be followed in the securitization proceeding, DEC and the Public Staff agreed that to demonstrate quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1)g., DEC must show that the net present value of the costs to customers using securitization is less than the net present value of the costs that would result under traditional storm cost recovery. For purposes of settlement for the Storm Costs only, the stipulating parties agreed that when conducting this comparison in the subsequent securitization docket for the Storms, the following assumptions shall be made:

(1) For traditional storm cost recovery, 12 months of amortization for each Storm was expensed prior to the new rates going into effect;
(2) For traditional storm cost recovery, no capital costs incurred due to the Storms during the 12-month period were included in the deferred balance;
(3) For traditional storm cost recovery, no carrying charges were accrued on the deferred balance during the 12-month period following the date(s) of the Storm(s);
(4) For traditional cost recovery, the amortization period for the Storms is a minimum of ten years; and
(5) For securitization, the imposition of the Storm recovery charge begins nine months after the new rates go into effect.

Id., § III.3.

DEC and the Public Staff further agreed that pursuant to N.C.G.S. § 62-172, the amortization of securitized Storm Costs shall not begin until the date the storm recovery bonds are issued. *Id.*, § III.4.

DEC and the Public Staff also agreed that a storm cost recovery rider initially set at $0 should be established in this rate case, and if DEC does not file a petition for a financing order or is unable to recover the Storm Costs through N.C.G.S. § 62-172, the Company may request recovery of the Storm Costs from the Commission by filing a petition requesting an adjustment to this rider. In such case, DEC and the Public Staff reserve the right to argue their respective positions regarding the appropriate ratemaking treatment for recovering the Storm Costs. *Id.*, § III.5.

Finally, DEC and the Public Staff agreed to file a joint petition for rulemaking to establish the standards and procedures that will govern future financing petitions under N.C.G.S. § 62-172 upon the issuance of storm recovery bonds for the Storm Costs. *Id.* at Section III.6. No other party provided evidence on DEC's Storm Costs or its storm response and recovery procedures, and no party contested the conclusions of the Company and the Public Staff that DEC's Storm Costs were reasonable and prudent.

Discussion and Conclusions

Based upon the evidence and the record, the Commission finds and concludes that DEC's actual costs incurred to respond to and recover from Hurricanes Florence and Michael and Winter Storm Diego, totaling $213.1 million, and consisting of approximately $169.8 million in actually incurred or projected storm response O&M costs, capital investments of $18.6 million (including deferred depreciation expense), and $24.7 million in carrying costs (calculated using the Company's approved weighted average cost of capital, through July 31, 2020) were reasonable and prudent, to the extent such costs represent actual amounts as of May 31, 2020. Any estimated costs as of that date or incurred afterward should remain subject to review in the financing proceeding conducted pursuant to SB 559, or to consideration for recovery in a future general rate case proceeding, pursuant to the provisions of N.C.G.S.§ 62-172(a)(14)(c). Any updates to the deferred Storm Costs projections for storm recovery activities still underway should be provided at the time of the securitization filing.

The Commission also accepts DEC's removal of its Storm Costs from the revenue requirement requested in this proceeding in favor of a separate securitization filing, and the Commission further accepts the ten-year normalized adjustment to DEC's revenue requirement to account for anticipated storm expenses that are not large enough in size to securitize.

The Commission gives substantial weight to the Storm Cost provisions of the First Partial Stipulation and concludes that it is appropriate and consistent with SB 559 that DEC continue to defer its Storm Costs intended to be securitized in a regulatory asset account until the date on which the storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or alternative cost recovery is sought by the Company. The amounts recorded in the regulatory asset account will be subject to review by intervening parties and the Commission in the securitization proceeding. Further, it is appropriate and consistent with the statute that DEC continue to accrue and record carrying costs, at the Company's approved weighted average cost of capital, on the deferred balances in its Storm Costs recovery deferred account pending recovery through securitization, subject to review by intervening parties and the Commission in the securitization proceeding.

Consistent with DEC's and the Public Staff's agreement in their First Partial Stipulation, the Commission does not object to the Company's using the assumptions the Public Staff and DEC agreed to in the First Partial Stipulation to demonstrate quantifiable benefits to customers, in accordance with N.C.G.S. § 62-172(b)(1)g. However, the Commission makes no determination in this proceeding as to whether the assumptions and conditions agreed to by the stipulating parties are appropriate for use in the calculation of the quantifiable benefits to customers. Rather, the Commission concludes that the appropriateness of the provisions of the First Partial Stipulation regarding the assumptions and methods to be utilized in the demonstration of quantifiable benefits to customers in accordance with N.C.G.S. § 62-172(b)(1)g are matters to be decided in connection with the Company's joint petition, along with DEP, for financing orders in the securitization docket. In addition, the Commission accepts the stipulation provision on the stipulating parties' agreement to file a joint petition for rulemaking to establish the standards and procedures that will govern future securitization petitions under N.C.G.S. § 62-172.

The Commission also finds appropriate and reasonable the provisions of the First Partial Stipulation regarding the filing procedure for the securitization proceeding, the agreed-to delay in beginning the amortization of securitized costs, the provisions for establishing a provisional deferral of the storm costs pending the outcome in the securitization docket, and the commitment to pursue a rulemaking proceeding for future securitizations. The Commission concludes that these provisions serve to protect the interests of the Company and its ratepayers.

Finally, the Commission accepts the provision of the First Partial Stipulation to adopt a contingent storm cost recovery rider as a place holder in the event that securitization of the costs is denied and recognizes that DEC and the Public Staff have reserved their rights to argue their respective positions regarding the appropriate ratemaking treatment for the Storm Costs.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 62–63

Adjustments to Plant in Service

The evidence supporting these findings of fact is found in the verified Application and Form E-1, the testimony and exhibits of Public Staff witness Metz and Boswell, and the entire record in this proceeding.

Summary of the Evidence

Public staff witness Metz recommended that the capital costs associated with the Lincoln County Combustion Turbine 17 (LCCT 17) project be removed from rate base. He further recommended that the capital costs associated with Project Focal Point 12 also be removed from rate base. Witness Metz testified that he was recommending the removal of the LCCT 17 project due to language that was included in the Commission's order approving the LCCT 17 CPCN in Docket No. E-7, Sub 1134 issued on December 7, 2017. He stated that the order granted the Lincoln County CT CPCN on the condition that "DEC will not seek cost recovery before the later of December 1, 2024, or the date by which DEC has taken care, custody and control and placed the unit into commercial operation."

Witness Metz noted that this language was clear — DEC was not to include any costs of the LCCT 17 and associated transmission lines in rates until after December 1, 2024. Witness Metz indicated that based on his review DEC had included certain costs associated with the support and operation of LCCT 17 in rate base in the May 2020 Updates. Public Staff witness Metz further stated that it was his understanding that DEC agreed with the removal of these costs. Witness Metz recommended a total of approximately $14.3 million (system basis) be removed from rate base. Further, Witness Metz testified that once the project meets the conditions set forth in the Commission's Sub 1134 order, the project cost(s) may be properly included in any general rate case request for cost recovery at that time. He took no stance on reasonableness or prudence of these costs.

With regard to the Focal Point Project (Focal Point), witness Metz testified that Focal Point is a corporate-wide initiative to replace and upgrade older monitoring and recording equipment (e.g., cameras) with modern, state of the art equipment. He noted that once this upgrade is complete, it is intended to be an overall upgrade to Duke Energy's security system. Witness Metz testified that his reasoning for recommending removal of these costs was due to the fact that these costs were for equipment that is not fully installed and operational. Witness Metz recommended a total system cost adjustment of approximately $3.7 million. He stated that these should be sought for cost recovery once installed. He further noted that DEC agreed to not request cost recovery in this proceeding.

Witness Metz testified that both of his adjustments had been incorporated into the schedules and exhibits presented by Public Staff witness Boswell.

Discussion and Conclusions

In light of the evidence presented in this proceeding, the Commission finds and concludes that the adjustments to remove the costs associated with the LCCT 17 and Focal Point projects are appropriate and just. Both parties agree the costs related to both the LCCT 17 and Focal Point projects should be removed from rate base in the current proceeding. The Commission agrees that the instant proceeding is not the proper place to seek recovery of these costs at this time. The Commission agrees that its language in its order in Docket No. E-7, Sub 1134 is clear. DEC is not to seek recovery of costs related to the LCCT 17 and associated transmission lines until after December 1, 2024. With regard to the Focal Point costs, the Commission does not consider these costs ripe for cost recovery because they are for equipment that is not installed or operational. As such, the Commission finds that these costs should be removed from rate base at this time.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 64

Prepaid Advantage Program

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEC witness Barnes, Public Staff witness Floyd, and NCJC et al. witness Howat; and the entire record in this proceeding.

Summary of the Evidence

On August 2, 2019, DEC filed a Petition for Approval of Prepaid Advantage Program in Docket No. E-7, Sub 1213, requesting to offer customers the billing option to prepay for service, thereby avoiding the need for a deposit, reconnection fees, and late fees. DEC further requested that the Commission waive certain Commission Rules related to the monthly bill format, payments, and disconnection, specifically Rules R8-8, R8-20(b), (c), and (d), R8-44(4)(d), R12-8, R12-9(b), (c), and (d), and R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p). The Public Staff presented the Prepaid Advantage Program for approval at the Commission's Regular Staff Conference on November 12, 2019. On November 20, 2019, the Commission issued an order consolidating DEC's request with DEC's general rate case application.

Company witness Barnes testified in support of the Prepaid Advantage Program. Witness Barnes explained that by utilizing the benefits of smart meters, the program will offer customers the voluntary billing option to prepay for electric service in advance of usage, thereby providing various customer benefits, including avoiding the need for a deposit, reconnect fees, or late fees. Tr. vol. 11, 719. She further explained that DEC introduced a similar prepaid advantage program in its South Carolina service territory in 2015 that has successfully delivered increased customer satisfaction and energy savings — on average, participating South Carolina customers experienced an 8.5% reduction in their energy usage. *Id.* Witness Barnes could not definitively state whether the energy usage reductions were a result of the South Carolina program's design as a whole or as individual features of the program. Tr. vol. 13, 161-62.

Public Staff witness Floyd summarized the Prepaid Advantage Program as follows: new or existing customers with smart meters may elect to participate in this program are enrolled in the Equal Payment Plan, have an active deferred payment arrangement exceeding $500, or are identified as a medical alert customer pursuant to Commission Rule R12-11(q). Customers will have the ability to review daily usage information through a secure web portal accessible by a computer or smartphone with internet, as well as receive account notifications via phone, email, or text message. Tr. vol. 18, 289. Witness Floyd stated that to enroll, participants will be required to make an initial payment of at least $40. *Id.* at 290. Participants with an outstanding balance when enrolled in the Prepaid Advantage Program will have 25% of any payments credited toward the unpaid balance until that balance is satisfied. After enrollment, participants can increase their account balances as frequently as they desired. *Id.*

Witness Floyd explained that the Prepaid Advantage Program is designed to provide participants with frequent notices regarding their account balance, including five, three, and one-day notifications prior to their account reaching a zero balance. *Id.* As such, customers will be required to provide DEC with a notification channel preference such as text, email, or phone by which DEC would communicate with them regarding their account balances and usage. Once an account reaches a zero balance, the customer will have until the next business day to make a payment before the customer's service is remotely disconnected. *Id.* To have service reconnected, the customer must pay any outstanding balance and make an additional payment towards future service. *Id.* Service may be reconnected remotely (within approximately 15 minutes) following payment after a disconnection. *Id.* at 290-91. Payments can be made online through the program portal, over the phone, or in person. *Id.* at 291). Billing rates for service will be the same as those for traditional post pay service (Schedule RS). However, rates for basic customer charges, taxes, and other per account or flat charges will be applied to the prepaid account on a daily pro-rata basis. *Id.*

Public Staff witness Floyd also noted that New River Light and Power Company presented to the Commission a similar prepaid service program in Docket No. E-34, Sub 49 — in terms of process, mechanics, and waiver of Commission rules — that the Commission approved on June 25, 2019, and that 20 of 26 North Carolina-based electric membership cooperatives provide some form of prepayment option for customers. *Id.* at 293. He stated that he believes that DEC customers would be interested in the program. Witness Floyd testified that the Prepaid Advantage Program should be approved with certain conditions and reporting requirements. *Id.* at 299. He also recommended that the following conditions for the requested waiver of Commission rules apply:

1. No disconnection before 3:00 p.m. to allow affected customers as much time as possible to make the necessary payments;
2. That the Company makes all reasonable efforts to have on file a third-party designee, selected by the customer, who will receive any notice of termination in addition to the customer; and
3. That the limited waiver to Rule R12-11(m)(2) would expire on June 30, 2021, unless otherwise extended by the Commission.

Id. Witness Floyd further recommended that DEC should confirm the ability of Prepaid Advantage Program participants to receive communications from the Company upon enrollment and noted that customers who were not able to receive notifications from the Prepaid Advantage Program should be ineligible for the program. *Id.* at 300.

Finally, witness Floyd recommended that DEC submit quarterly reports on the performance of the Prepaid Advantage Program by calendar month. *Id.* at 301. He stated that the Public Staff would work with the Company to refine the information needed, but believed such reporting should include at least the following items: (1) number of participants enrolled on the last day of each month, (2) number of participants that withdraw from the Prepaid Advantage Program and return to standard arrears billing, (3) average number of transactions observed per participant, distinguished by the method of payment used, (4) distribution of payment amounts (from least to most) and the average amount added to the account per transaction, (5) distribution of disconnections per participant, (6) number of participants with more than one disconnection in a 90-day period, (7) total number of disconnections, (8) average customer balance at time of disconnection, and (9) average time from disconnection to reconnection. *Id.* at 301-02.

Company witness Barnes testified that DEC agreed to waive the transaction fee for any transaction involving credit and debit cards or electronic checks for the program's participants and also agreed to each of the Public Staff's recommended conditions and reporting requirements. Tr. vol. 11, 719-21.

NCJC et al. witness Howat expressed his concerns with utility prepaid programs, in general, and recommended that DEC's Prepaid Advantage Program be denied. Tr. vol. 17, 600. He testified that the Prepaid Advantage Program is not an affordability program that enhances low-income energy security and observed that prepaid programs are typically composed of a variety of features, some of which are helpful for customers such as provision of timely information regarding energy usage and expenditures. *Id.* at 589, 600. He also testified that lower income households tend to enroll more frequently in prepaid services because there is often no deposit required and those enrolled in prepaid services are disconnected from electricity service more frequently than those customers enrolled a traditional billing program. *Id.* at 590.

Witness Howat also outlined the important consumer protections removed by the Prepaid Advantage Program which he believed would bring considerable risk for customers' energy security, including secure, reliable notification prior to disconnection of service, limitations on disconnection under certain circumstances, the right to dispute a bill, and special protections for the elderly and disabled. Tr. vol. 17, 589-91. Witness Howat was particularly concerned with the period of time between when a customer's billing credits expire and when their utility service is shut off. Tr. vol. 10, 145. Witness Howat also referenced, and agreed with the criticisms contained in, the letter from Mr. Alfred Ripley and others on behalf of the NCJC and other organizations filed with the Commission in Docket No. E-7, Sub 1213. Tr. vol. 17, 592; NCJC et al. Ex. JH-7. The NCJC's letter expressed particular concern with the Company's proposal to allow rapid remote disconnections while at the same time waiving several Commission rules providing protections for disconnections. *Id.*

Finally, witness Howat pointed out that the customer benefits gained from prepaid service are not exclusive to the prepaid program but flow from various features of the programs. Tr. vol. 17, 591; tr. vol. 10, 143. Witness Howat also noted that the Company's customers already have the option to pay their electricity bills in advance of receiving their monthly bill and instead supported additional tools to augment this ability. Tr. vol. 10, 144; tr. vol. 17, 591.

Company witness Barnes disagreed with witness Howat's testimony. She testified that the Prepaid Advantage Program was voluntary to any customer who wants an alternative billing and payment arrangement, not limited to low-income customers, but rather held advantages for some low- or fixed-income customers. Tr. vol. 11, 723. Witness Barnes testified that many of the Company's South Carolina prepaid program's low- or fixed-income participants reported benefitting from this payment flexibility. *Id.* Witness Barnes instead agreed with Public Staff witness Floyd that the Prepaid Advantage Program maintains many customer protections and appropriately balances those with the many benefits to participating customers, as well as the need to have appropriate disconnection procedures to protect all customers. *Id.* at 724.

Public Staff witness Floyd also addressed the issues raised in Mr. Ripley's letter and explained that the Public Staff considers the disconnection procedure proposed by the Company for prepaid accounts that reach zero balances to be reasonable. Tr. vol. 18, 296. He highlighted that a customer would receive periodic notices through the communication channel of her choice prior to an account reaching a zero balance and that the actual disconnection would not occur until the next business day, and only under fair weather conditions. Witness Floyd explained that extreme weather conditions and holidays would result in the postponement of disconnection, likely until the next fair-weather business day. *Id.*

Witness Floyd further testified that this short time frame needs to be as small as possible to reduce the amount of energy sales that go uncompensated. *Id.* Otherwise, he explained, the Prepaid Advantage Program would run the risk of increasing lost sales revenues that add to the Company's uncollectible expenses. As such, witness Floyd believes that the process of disconnection only on fair weather business days provides ample protections for those who voluntarily participate in the Prepaid Advantage Program. *Id.* at 296-97.

Witness Floyd also disputed Mr. Ripley's concern that the Prepaid Advantage Program lacked certain attributes recommended by a National Association of State Utility Consumer Advocates (NASUCA) resolution. Tr. vol. 18, 297-98. To the contrary, he explained that many of those attributes are incorporated into the design and implementation of DEC's Prepaid Advantage Program, including that: (1) a grace period exists between a zero balance and disconnection, (2) certain customer segments are ineligible due to medical conditions, (3) the program is voluntary, (4) participants avoid the need for security deposits, (5) participants can increase their account balances at any time, (6) participants can return to postpaid service at any time, subject to the requirements of a security deposit and other costs associated with postpaid accounts, and (7) prepayments are immediately posted to customer's account. *Id.*

Finally, as part of the Second Partial Stipulation, DEC and the Public Staff agreed that the Prepaid Advantage Program should be approved, subject to the conditions in the Commission's November 15, 2019 order in Docket No. E-7, Sub 1210. Second Partial Stipulation, § IV.F.

Discussion and Conclusions

After careful consideration, the Commission agrees with the Company and the Public Staff that the Prepaid Advantage Program will provide customers who choose to enroll with greater flexibility and control over their electric usage and payments. By waiving the deposit and other fee requirements, the Company has increased the benefits to participating customers, especially low- or fixed-income customers. The Commission notes that the program is completely voluntary, but nevertheless appreciates and recognizes the concerns raised by NCJC et al. The Commission gives substantial weight to the testimony of the Public Staff in this regard and thus adopts the safeguards proposed by witness Floyd, namely that: (1) there shall be no disconnection before 3:00 p.m., (2) the Company shall make all reasonable efforts to have on file a third party designee, selected by the customer, who will receive any notice of termination in addition to the customer, and (3) DEC shall confirm the ability of Prepaid Advantage Program participants to receive communications from the Company upon enrollment. Additionally, the Commission gives substantial weight to and thus adopts the Public Staff's recommendations regarding reporting requirements, which the Company has accepted. Accordingly, the Commission concludes that the provision of the Second Partial Stipulation agreeing that the Prepaid Advantage Program should be approved is reasonable and in the public interest. The Prepaid Advantage Program is therefore approved subject to the conditions as set forth herein and as accepted in the Second Partial Stipulation. The Commission also approves DEC's requested waiver of the requirements of Commission Rules R8-8, R8-20 (b), (c), and (d); R8-44(4)(d); R12-8; R12-9(b), (c), and (d); and R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p), only with respect to service rendered under the Prepaid Advantage Program.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 65–67

AMI and Green Button Connect

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEC witnesses Schneider, Pirro, and Hatcher, Public Staff witness Floyd, and Commercial Group witness Chriss; and the entire record in this proceeding.

Summary of the Evidence

DEC witness Schneider testified that DEC installed approximately one million AMI meters from July 1, 2018, through June 30, 2019, bringing DEC's total installed AMI meters to two million, with deployment of AMI being almost complete in North Carolina. He testified that DEC expended $118.4 million on AMI meters in North Carolina and South Carolina from January 1, 2018, through June 2019, and projects that it will spend $9.1 million from July 1, 2019, through December 31, 2019, the project end date. In addition, he testified that DEC enrolled 1.627 customers in its opt-out program from October 2018 through June 2019. Tr. vol. 13, 139-40.

Witness Schneider further testified to the benefits of AMI, including customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, and new time-of-use rate designs. *Id.* at 140-44.

DEC witness Pirro testified that DEC reviewed its costs of Rider MRM, the AMI meter opt-out tariff approved by the Commission in 2018 in Docket No. E-7, Sub 1115. He stated that the updated costs could justify an increase in the one-time setup fee from its present level of $150 to $230, and the monthly fee from $11.75 to $14.05. However, DEC is not requesting an increase in the fees because Rider MRM has been in effect less than one year and the Company believes adjusting the fees associated with opt-out is premature. Tr. vol. 12, 255.

Public Staff witness Floyd testified that the Public Staff agrees with DEC's decision not to increase the AMI setup fee and monthly fee at this time. In addition, he stated that DEC has enrolled 884 residential and small general service customers in Rider MRM, with 663 having been found eligible for waiver of the fees. He stated that the Public Staff believes that Rider MRM costs that are not recovered from customers opting out of AMI meters should be recovered from all DEC customers. Tr. vol. 18, 279-81.

Witness Floyd further testified that DEC's customers will see a benefit from AMI by a reduction in connection and reconnection fees. He stated that DEC proposes reducing its connection fee from $24.18 to $10.51, and its reconnection fee from $27.13 to $9.25. He further stated that these changes are supported by the Company's cost calculations. *Id.*

In Section IV.I of the Second Partial Stipulation, DEC and the Public Staff agreed that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEC customers.

Commercial Group witness Chriss recommended in his direct testimony that the Commission require DEC to include Green Button "Connect My Data" (Green Button) as part of the Company's means of providing access to electric usage data. Tr. vol. 16, 77-78. In the Commercial Group Stipulation, the parties agreed in Paragraph No. 5 that the Company met with Commercial Group and adequately addressed its concerns regarding data access and Green Button.

During the hearing, in response to questions by the AGO and on redirect, Company witness Hatcher testified that the benefits of AMI include enhanced customer information and control over their consumption of electricity, the opportunity to pick their payment due date and to receive usage alerts, and benefits related to storm response. Tr. vol. 11, 956-57, 1016-17.

In its post-hearing brief the AGO contended that DEC plans to integrate AMI meters with its Customer Connect billing platform using My Duke Data Download, characterized by the AGO as a nonstandard, outdated technology. Tr. vol. 11, 968; AGO Hatcher Cross-Examination Ex. 2. According to the AGO, DEC modeled its technology on older technology called Green Button Download that has more limited capabilities than the standard technology now available. The AGO asserted that if DEC had incorporated the advanced and readily available Green Button, or a similar technology, customers could conveniently access their data and authorize automated access by third parties *Id.* at 968, 973. As a result, the AGO requested that DEC be required to file revised Customer Connect plans that incorporate Green Button or another similarly advanced standard technology, or if that is not possible, the AGO requested that DEC be required to propose an alternative plan.

Discussion and Conclusions

The testimony of DEC's witnesses Schneider and Pirro, as well as Public Staff witness Floyd, provides substantial evidence that DEC has continued its deployment of

AMI meters since the Commission's 2018 DEC Rate Order in a prudent manner and that the costs of such continued deployment are reasonable. In addition, the testimony and the Second Partial Stipulation provide substantial evidence that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEC customers.

With respect to the AGO's contention that DEC should be ordered to implement Green Button, the Commission is not persuaded. The Commission has an ongoing investigation and rulemaking in Docket No. E-100, Sub 161 on customer and third-party access to electric usage data. Numerous parties, including the AGO, have filed comments and proposed rules, some of which include guidelines for the possible role of Green Button.

Based on the foregoing, the Commission concludes that DEC should be allowed to recover its costs of AMI deployment, and that the Rider MRM costs that are not recovered from opt-out customers should be recovered from all DEC customers. In addition, the Commission concludes that it should not require DEC to incorporate Green Button into its Customer Connect billing system at this time.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 68–71

Service Regulations, Vegetation Management, and Quality of Service

The evidence supporting these findings of fact is found in the verified Application and Form E-1; the Public Staff Second Partial Stipulation; the testimony and exhibits of DEC witnesses Pirro, Oliver, McManeus, and Hatcher, Public Staff witnesses Floyd, David Williamson, Tommy Williamson, and Boswell; and the entire record in this proceeding.

Summary of the Evidence

Service Regulations

In his direct testimony and his Exhibit 1, Company witness Pirro identified DEC's proposed changes to several charges contained in its service regulations that DEC proposed to be effective for service rendered on and after October 30, 2019. According to witness Pirro, the changes are intended to better reflect current cost studies along with the benefits of Smart Meter implementation. Tr. vol. 12, 236, 256; Pirro Ex. 1, DEC's North Carolina Retail Electric Rate Schedules and Service Regulations. The proposed changes include decreases in: (1) the Connect Charge from $24.18 to $10.51, and (2) the Reconnect Charge to restore service during normal business hours from $27.13 to $9.25 and during all other hours from $27.13 to $10.58. *Id.* at 256. Other proposed changes include corrections to typographical errors and a few other minor revisions and clarifications described in DEC witness Pirro's direct testimony. *Id.* at 256-57.

Public Staff witness Floyd testified that he reviewed the Company's proposed changes to its connection and reconnection fees and that he believes them to be reasonable. Tr. vol. 18, 281. No party testified in opposition to the Company's proposed changes to its Service Regulations or cross-examined the Company's witnesses on this issue at the hearing.

Vegetation Management

In his prefiled direct testimony, DEC witness Oliver testified that vegetation management is a critical component of the Company's customer delivery operations. He stated that the Company uses a combination of a reliability-based and a time-based prioritization model to drive its vegetation management program. He indicated that the Company's need for a funding increase adjustment for the program is two-fold. First, contractor labor costs have increased from the levels upon which the Company's current annual vegetation management costs are calculated. Tr. vol. 11, 609. Second, the number of annual miles targeted for vegetation management has also increased due to Hurricanes Florence and Michael and Winter Storm Diego. *Id.* In DEC witness McManeus' direct testimony and exhibits, she calculated the distribution system vegetation management cost increase to be $5,490,000, the amount found reasonable in Sub 1146. McManeus Direct Ex. 1, Item NC 2701, line 2.

In their direct testimony, Public Staff witnesses Tommy Williamson and David Williamson testified that they investigated the Company's vegetation management activities and found that the Company has eliminated 6,859 miles of the 13,467 miles of vegetation management backlog identified in Docket No. E-7, Sub 1146. Tr. vol. 17, 295-97. They also testified that the Company is on track to eliminate the remaining vegetation management backlog by 2022. *Id.* at 297. Nevertheless, they testified that Public Staff recommends that the Commission continue to require the Company to file semi-annual VM Plan reports as outlined in the Commission's Orders in Docket Nos. E-7, Subs 1146 and 1182, so that Public Staff may monitor the reports and inform the Commission of any issues or if it appears the Company is no longer on track to eliminate the backlog. They further agreed that the Company's target annual miles have increased, and that contract labor charges have also increased. *Id.* at 298. As a result, the Public Staff agreed that the 3% increase cited by the Company in contract labor charges is reasonable. *Id.*

The Public Staff witnesses further testified, however, that their analysis uncovered an error in the Company's calculation of vegetation management costs per mile and corrected that calculation before reporting the results of their investigation to Public Staff witness Boswell. *Id.* at 299. According to them, the Company utilized the wrong dollar amount per mile trimmed for the test period. Witness Boswell thus appropriately made an adjustment of $205,000 to the Company's proposed annual vegetation management cost increase. *Id.*; tr. vol. 17, 254-55; Boswell Ex. 1, Schedule 3-1(d).

DEC did not dispute the Public Staff's adjustment, and no other party presented evidence on DEC's annual vegetation management costs or cross-examined the Company's witnesses on this issue.

Service quality

DEC witness Hatcher provided testimony relating to the Company's service quality and ways in which the Company is working to enhance the customer experience. Tr. vol. 11, 898-99. Witness Hatcher noted that customer satisfaction (CSAT) is a key focus area for DEC. *Id.* at 898, 907. He explained that using data and analytics the Company is executing a long-term, customer-focused strategy designed to deliver greater value to its customers. *Id.* at 900. The Company's CSAT program includes both national benchmarking studies and proprietary transaction and relationship CSAT studies. *Id.* at 907-08. Witness Hatcher explained that the Company analyzes the results from these studies in vigorous monthly data review sessions, with findings driving improvements to processes, technology and behaviors — all to continuously improve the customer experience. *Id.* Specifically, he explained that DEC measures overall customer satisfaction and perceptions about the Company via its proprietary relationship survey, the Customer Experience Monitor Survey (CX Monitor Survey), which randomly measures customer loyalty and ongoing perceptions of several customer classes. *Id.* at 908. The CX Monitor Survey data is used to calculate the Company's Net Promoter Score (NPS), a top metric used by companies across industries to measure customer advocacy. *Id.* at 899-900. He indicated that since 2019 the Company has seen a significant increase in its NPS, with some of the Company's highest NPS scores occurring between the months of September and December of 2018, overlapping times of major storms. *Id.* at 909.

DEC witness Hatcher also explained that in addition to its relationship study, DEC utilizes Fastrack 2.0, the Company's proprietary, post-transaction measurement program, to measure overall customer satisfaction with the Company's operational performance. Tr. vol. 11, 909-10. Fastrack 2.0 was designed to complement the CX Monitor survey and provide insight into experiences that matter to DEC's customers and near real time feedback to front line, customer-facing employees. *Id.* at 914. Witness Hatcher explained that analysis of these ratings helps identify specific service strengths and opportunities that drive overall satisfaction and provides guidance for the implementation of process and performance improvement efforts. *Id.* Through 2018, roughly 80% of DEC residential customers expressed high levels of satisfaction with key service interactions: Start/Transfer Service, Outage/Restoration, and Street Light Repair. *Id.* at 910. Witness Hatcher stated that the Company has also implemented "Reflect," a post-contact survey that gathers customers' immediate feedback after contacting Duke Energy by web, text, call to automated system, or live agent. *Id.*

Witness Hatcher further explained that the Company is working hard across its business to further improve the customer experience by making strategic, value-based investments for the benefit of customers. *Id.* at 916. Key examples include enhancements to the Company's integrated voice response (IVR) system and the deployment of Customer Connect. *Id.* at 916-19. Finally, witness Hatcher identified additional programs to improve customer service, explaining that the Company seeks approval to eliminate convenience fees for credit and debit card payments made by residential customers, as well as to extend the bill payment due date for nonresidential customers from 15 days to 25 days. *Id.* at 920-24, 926-27.

Public Staff witnesses David Williamson and Tommy Williamson also jointly testified regarding DEC's quality of service. Tr. vol. 17, 292-94. In evaluating the Company's overall quality of service, they reviewed the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability scores filed by DEC with the Commission in Docket No. E-100, Sub 138A; informal complaints and inquiries from DEC customers received by the Public Staff's Consumer Services Division; the consumer statements of position filed in Docket No. E-7, Sub 1214CS; and the Public Staff's own interactions with DEC and its customers. *Id.* They noted that for the period 2010 through 2019, Company reports show the SAIDI and SAIFI indices are worsening. *Id.* at 293. However, they noted there has been some realized improvement for calendar year 2019, primarily from a reduction in vegetation and equipment failure related outages, compared to the previous year. They concluded that the quality of service provided by DEC to its North Carolina retail customers is adequate at this time. *Id.*

DEC and the Public Staff further agreed in Section IV.M. of the Second Partial Stipulation that the Company's quality of service is good. No party offered any evidence contradicting this assessment.

Discussion and Conclusions

The Commission concludes that the Company's proposed amendments to its Service Regulations are reasonable and appropriate and should be approved.

The Commission also concludes that DEC's vegetation management performance is reasonable and that it is appropriate to adopt and incorporate into the Company's costs the adjustments to annual vegetation management costs per mile and annual vegetation management expense that Public Staff witnesses Boswell and Williamsons applied in their testimony to the Company's proposed annual costs. The Company shall continue to file semi-annual vegetation management reports as directed in Docket Nos. E-7, Subs 1146 and 1182, and the Public Staff shall monitor the reports and inform the Commission if there are any issues or if it appears the Company is no longer on track to eliminate the 2017 vegetation management backlog.

Finally, the Commission finds and concludes that the overall quality of electric service provided by DEC is good.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 72

Accounting for Deferred Costs

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, and the entire record in this proceeding.

In the present case, the Commission is approving DEC's recovery through amortization of a previously deferred portion of DEC's CCR costs. A deferred cost is an exception to the general principle that the Company's current cost-of-service expenses should be recovered as part of the Company's current revenues. As a result, a deferred cost is not the same as the other cost-of-service expenses to be recovered in the Company's non-fuel base rates and, therefore, should be subject to different accounting guidelines.

When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost, the Commission identifies a specific amount that has already been incurred by the Company or is estimated to be incurred by the Company. In addition, with respect to deferral of costs already incurred, the Commission sets the recovery of the amount of those costs over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If the Company continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DEC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 73

Just and Reasonable Rates

The evidence supporting this finding of fact is found in the verified Application and Form E-1, the testimony and exhibits of the witnesses, including DEC witnesses De May, Immel, Capps, and Schneider, and the entire record in this proceeding.

As previously discussed, pursuant to N.C.G.S. § 62-133(a) the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. N.C.G.S. § 62-133(b). DEC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DEC's individual customers, as well as to the communities and businesses served by DEC. The Company presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

DEC witness De May testified that the Company is experiencing significant changes throughout many aspects of the electric industry, and that the investments DEC has made and must continue to make are designed to keep pace with evolving customer needs and expectations. Witness De May stated that the Company's investments are capital intensive, and the Company has incurred costs that are not included in its current rates. As one example, he stated that DEC's customers want more information about how they consume energy and more tools that help them manage their consumption. According to witness De May, DEC is responding by investing in a more efficient distribution grid, AMI meters, and cleaner and more efficient generation units. In addition, he stated that DEC is actively working toward achieving a lower carbon future by taking steps to reduce its reliance on coal-fired generation, including investments in generation resources like natural gas and solar. Moreover, witness De May testified that DEC is committed to helping customers who struggle to pay for essential needs like electricity with programs and options to assist them, such as the Share the Warmth program, and DSM and energy efficiency programs. Tr. vol. 11, 857-62. Indeed, as part of the First and Second Partial Stipulations, DEC will make shareholder-funded contributions, in conjunction with the concurrent commitment of DEP, of a combined $3 million per year for two years to the Helping Home Fund, for a total of $6 million. Further, DEC will make an annual $2.5 million shareholder-funded contribution to the Share the Warmth Fund in 2021 and 2022, for a total contribution of $5 million.

Witness De May and other witnesses also described the importance of DEC maintaining a strong financial position in order to facilitate the Company's investments in utility service infrastructure. He stated that the Company's strong financial position and performance benefit customers by reducing DEC's cost of borrowing and cost of attracting equity capital. *Id.* at 863-65. As previously discussed, the Commission does not set rates based on DEC's credit metrics. Rather, the Company's credit ratings and other credit metrics are the responsibility of the Company to manage. Nonetheless, the Commission has considered the evidence on potential credit impacts and given that evidence due weight as a part of the Commission's ratemaking task that requires the Commission to set rates that are fair to DEC and its ratepayers. N.C.G.S. § 62-133. The utility's access to credit at a reasonable cost is important to both DEC and its ratepayers. Both benefit if DEC can obtain credit at the best interest rates reasonably possible. The Commission concludes that the rates set herein achieve the appropriate balance of being credit supportive for DEC and fair to DEC's ratepayers.

In addition, DEC witness Immel testified that since its previous rate case the Company has made capital investments in its fossil, hydroelectric, and solar generating units that enable the Company to continue to provide safe and reliable generation. He gave as an example, investments of approximately $689 million to meet environmental regulations and allow for the continued operation of active coal-fired plants, largely driven by dry bottom ash conversions, wastewater treatment enhancements, and lined retention basin projects. He further testified that DEC converted its coal-fired Cliffside Station and Belews Creek Unit 1 to burn natural gas as well as coal, with Cliffside Unit 5 now capable of burning up to 40% natural gas, Cliffside Unit 6 up to 100%, and Belews Creek Unit 1 up to 50%. He stated that this co-firing capability allows DEC to utilize the most cost-effective fuel at any given time, providing the Company with fuel flexibility for the benefit of customers. Tr. vol. 12, 56-58.

DEC witness Capps testified that since DEC's last rate case in 2017 the Company has invested approximately $440 million in capital investments at its Catawba, McGuire, and Oconee nuclear plants. He stated that the investments were necessary to improve safety, comply with new or revised regulatory requirements, enhance reliability, and to manage aging and obsolescence. He provided details of the capital improvements at the three plants, such as IT infrastructure upgrades in 2019. He stated that these upgrades consisted of installing new backbone fiber networks that build on the existing networks, modernizing each station's IT capabilities and supporting additional automated plant monitoring functions. Moreover, he provided testimony about the improvements made in response to cybersecurity concerns and requirements of the Nuclear Regulatory Commission. He also testified that approximately 33% of the required O&M expenditures for DEC's nuclear fleet were fuel-related, and he described how DEC has worked diligently to control the O&M costs of its nuclear fleet. Tr. vol. 11, 732-39.

Witness Schneider testified to DEC's installation of approximately one million AMI meters from July 1, 2018, through June 30, 2019, at a cost of approximately $127.5 million. In addition, he testified to the customer benefits of AMI, including lower cost O&M due to remote disconnections and reconnections, customer access to more usage information, speedier storm outage detection and restoration, more flexibility in customer billing dates, and new time-of-use rate designs. Tr. vol. 3, 139-44.

These are representative examples of the capital investments that have been made and are planned by DEC in order to continue providing safe, reliable, and efficient electric service to its customers. In this time of COVID-19, with many people working and schooling at home, the importance of safe, reliable, and efficient electric service is heightened beyond its normal level as an essential service.

Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DEC's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DEC in maintaining the Company's financial strength at a level that enables the Company to obtain sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of the Act and serve the public interest.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 74

Revenue Requirement

The evidence supporting this finding of fact is found in the verified Application and Form E-1; the Public Staff First and Second Partial Stipulations; the testimony and exhibits of the witnesses, including DEC witness McManeus and Public Staff witness Boswell; and the entire record in this proceeding.

The First and Second Partial Stipulations between the Company and the Public Staff provide for certain accounting adjustments that the Company and the Public Staff have agreed upon and the Commission has approved in this Order. The stipulated issues on revenue requirement effects are detailed in McManeus Supplemental Rebuttal Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1 (Partial Stipulation Revenue Requirement Exhibits), and Public Staff witness Boswell Second Supplemental and Settlement testimony.

DEC's McManeus Second Settlement Exhibit 2 shows DEC's revised requested increase incorporating the details of the Second Partial Stipulation and the Company's position on the remaining unresolved issues. The resulting proposed base revenue requirement of the Company is an increase of $414,433,000. Boswell Second Supplemental and Stipulation Exhibit 1 reflects the Public Staff's revised recommended change in revenue requirement incorporating the provisions of the Second Partial Stipulation. In addition, it reflects the Public Staff's position on the remaining unresolved issues. The resulting proposed base revenue requirement by the Public Staff is an increase in the base rate revenue requirement of $290,049,000, which includes the settled stipulated positions of the Company and the Public Staff.

As discussed in the body of this Order, the Commission approves portions of the stipulations and makes its individual rulings on the unresolved issues. Due to the intricate and complex nature of some of the issues, the Commission concludes that DEC should recalculate the required annual revenue requirement consistent with the Commission's findings and rulings herein within ten days of the issuance of this Order. The Commission further concludes that DEC should work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an order with final revenue requirement numbers.

IT IS, THEREFORE, ORDERED as follows:

1. That the approved base fuel and fuel-related costs factors by customer class, are as follows: 1.6027 cents per kWh for the Residential class, 1.7583 cents per kWh for the General Service/Lighting class, and 1.6652 cents per kWh for the Industrial class;

2. That the Company shall amortize the loss on the sale of its hydro stations over a 20-year period;

3. That DEC shall include a return on the unamortized balance related to the loss on the sale of hydro stations;

4. That DEC shall use a 10% contingency for future "unknowns" in the estimate of future terminal net salvage costs

5. That DEC shall use an interim net salvage percentage of zero for Accounts 342, 343, 344, 345, and 346;

6. That DEC shall use an escalation of terminal net salvage cost and the straight-line method of depreciation in determining escalation as performed in the Decommissioning Study;

7. That DEC shall use its proposed future net salvage for mass property Account 366, Underground Conduit;

8. That DEC shall use an average service life of 15 years for the new AMI meters;

9. That the depreciation rates proposed by DEC in this case are approved, except as specifically modified by this Order.

10. That the depreciation rate for the Allen Units 4 and 5 and Cliffside Unit 5 generating plants shall not be changed, and shall be based upon the remaining life of the plants, as approved in DEC's rate case in Docket No E-7, Sub 1146;

11. That upon actual retirement of each generating unit, Allen Units 4 and 5 and Cliffside Unit 5, the remaining net book value shall be placed in a regulatory asset account to be amortized over an appropriate period to be determined in a future rate case;

12. That DEC's cost of capital investments in its coal fleet to meet environmental regulations to allow for the continued operation of active coal units shall be included for recovery in DEC's rates;

13. That DEC's costs related to the Belews Creek Unit 1 DFO project shall be included for recovery in DEC's rates;

14. That the stipulations of DEC with the Public Staff, CIGFUR, Harris Teeter, Commercial Group, Vote Solar, and jointly with NCSEA and NCJC et al. are accepted and approved in part, as detailed in this Order;

15. That DEC shall recover the balance of its deferred CCR costs reduced by $224 million in the present case and shall cease to accrue financing costs on this amount as of December 31, 2020, consistent with the CCR Settlement; and that DEC shall recover the balance of its deferred CCR costs over a five-year amortization period with reduced financing costs during the amortization period calculated based on (1) DEC's cost of debt set forth in the Second Partial Stipulation, adjusted as appropriate to reflect the deductibility of interest expense, (2) an ROE 150 basis points lower than the 9.60% ROE set forth in the Second Partial Stipulation, and (3) a capital structure of 48% debt and 52% equity set forth in the Second Partial Stipulation;

16. That DEC is authorized to record its February 1, 2020, and future CCR costs in a deferred account until its next general rate case; and that this deferral account will accrue a return at the overall rate of return approved in this Order consistent with the CCR Settlement;

17. That the agreed-upon accounting adjustments outlined in McManeus Supplemental Rebuttal Exhibit 3, McManeus Second Settlement Exhibit 3, Boswell Supplemental and Stipulation Exhibit 1, Schedule 1, and Boswell Second Supplemental and Stipulation Exhibit 1, Schedule 1 shall be, and are hereby, approved;

18. That the Company's revised Lead-Lag Study filed as Speros Supplemental Exhibit 3 shall be, and is hereby, approved for purposes of calculating the cash working capital amounts to be included in the Company's revised rates;

19. That DEC's request for an accounting order for approval to establish a regulatory asset to defer the North Carolina retail portion of incremental O&M expenses associated with the Company's severance program, as modified by the terms of the First Partial Stipulation, shall be, and is hereby, approved;

20. That DEC's request for deferral accounting for GIP expenditures is approved consistent with its Second Partial Stipulation with the Public Staff and subject to the conditions set forth in this Order;

21. That DEC shall work expeditiously with the Public Staff to refine its GIP reporting requirements, as intended under the Second Partial Stipulation, and file the first report for spending during the last half of 2020 by May 1, 2021;

22. That the proposed EDIT Rider, as modified by the terms of the DEC and Public Staff Partial Stipulations, is approved and shall be implemented; and that the protected federal EDIT will be removed from the EDIT Rider and returned to customers through base rates;

23. That the agreement between DEC and the Public Staff as outlined in the Second Partial Stipulation concerning how to address changes in the federal corporate income tax rate or North Carolina state corporate income tax rate, which may occur during the respective amortization periods is hereby approved;

24. That the CIGFUR Stipulation allowing EDIT and the provisional revenues to be flowed back based on a uniform cents per kWh basis is inappropriate and is hereby not approved;

25. That all federal unprotected EDIT and provisional revenues shall be flowed back based on the amounts each rate class paid, as recommended by Public Staff witness Floyd;

26. That the jurisdictional and class cost allocation methodologies proposed by the Company are approved and shall be implemented;

27. That DEC shall set the OPT-VSS off-peak energy charge at 3.0222 cents/kwh and the on-peak energy charge shall be increased by a percentage amount that is equal to half of the overall percentage increase for the OPT-VSS rate schedule. The demand charges for the OPT-VSS rate schedule shall be adjusted by the

amount necessary to recover the final OPT-VSS revenue target. Grid Improvement Plan costs allocated to OPT-V customers shall be recovered via OPT-V demand charges;

28. That the aspects of rate design agreed upon in the Public Staff Second Partial Stipulation are approved and shall be implemented;

29. That the Company shall conduct a comprehensive Rate Design Study as outlined in § IV.E of the Public Staff Second Partial Stipulation and further described herein with broad stakeholder engagement facilitated by a third party to be engaged by the Company; that the Company shall initiate the Rate Design Study with stakeholders no later than 30 days following the date of this Order; that the Company shall file quarterly status reports in this docket detailing the work of the Rate Design Study participants; and that the Company shall file a comprehensive roadmap and timeline for proposing new rate designs and identifying areas for additional study within 12 months of the date of this Order;

30. That the Company shall conduct an independent review and audit of its M&S inventory, to be performed by the Company's internal Corporate Audit Services department, and as further described in the Public Staff Second Partial Stipulation;

31. That the Company and the Public Staff shall meet to discuss the Company's plant unitization policies and reporting obligations;

32. That the Company's proposed modifications of certain outdoor lighting fees and schedules are approved;

33. That the Company shall convene a stakeholder process that is tasked with addressing affordability issues for low-income residential customers consistent with the terms of this Order;

34. That DEC, in conjunction with the concurrent commitment of Duke Energy Progress, LLC, shall make an aggregate combined shareholder-funded contribution to the Helping Home Fund of $3 million per year for two years (for a total of $6 million).

35. That DEC shall make an annual $2.5 million shareholder-funded contribution to the Share the Warmth Fund in 2021 and 2022, for a total contribution of $5 million.

36. That the Company's Storm Costs are reasonable and prudent;

37. That the terms of the Public Staff First Partial Stipulation providing for a contingent Storm Cost Recovery Rider set at $0 are approved;

38. That DEC's request to defer the Storm Costs in a regulatory asset account until the date that storm recovery bonds are issued pursuant to an approved financing order in accordance with N.C.G.S. § 62-172, or until the Company seeks recovery of the Storm Costs through an alternative method of cost recovery, is hereby approved;

39. That DEC's Prepaid Advantage Program shall be, and is hereby, approved;

40. That the rates for electric utility service applicable to the Prepaid Advantage Program shall be those as stated in Schedule RS, with the basic facilities charge, Renewable Energy Portfolio Standard (REPS) Rider, and any other flat rate per account charge applicable to Schedule RS applied to the Prepaid Advantage Program on a pro rata basis;

41. That DEC's requested waiver of the requirements of Commission Rules R8-8, R8-20 (b), (c), and (d); R8-44(4)(d); R12-8; R12-9(b), (c), and (d); and R12-11(a), (b), (f), (g), (h), (i), (l), (m), (n), and (p), shall be granted, only with respect to service rendered under the Prepaid Advantage Program, and with the following limitations on the waiver:

(a) No disconnection before 3:00 p.m. to allow affected customers as much time as possible to make the necessary payments;

(b) That the Company makes all reasonable efforts to have on file a third-party designee, selected by the customer, who will receive any notice of termination in addition to the customer; and

(c) That the limited waiver to Rule R12-11(m)(2) would expire on June 30, 2021, unless otherwise extended by the Commission;

42. That DEC shall work with the Public Staff to develop a quarterly report on the Prepaid Advantage Program to be filed beginning November 1, 2021, for the Third Quarter of 2021, and quarterly thereafter;

43. That the proposed amendments to DEC's Service Regulations shall be, and are hereby, approved;

44. That the Company shall continue to file semi-annual vegetation management reports as directed in Docket Nos. E-7, Subs 1146 and 1182;

45. That DEC shall recover its costs of deploying AMI meters;

46. That DEC shall recover its Rider MRM costs that are not recovered from customers opting out of AMI meters from all DEC customers;

47. That if DEC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset/liability account established for that deferred cost until the Company's next general rate case;

48. That DEC shall remove the costs associated with the LCCT 17 from rate base;

49. That DEC shall remove the costs associated with the Focal Point Project from rate base;

50. That DEC shall recalculate and file the annual revenue requirement with the Commission within ten days of the issuance of this Order, consistent with the findings and conclusions of this Order. The Company shall work with the Public Staff to verify the accuracy of the filing; and

51. That DEC shall file schedules (North Carolina Retail Operations — Statement of Rate Base and Rate of Return, Statement of Operating Income, and Statement of Capitalization and Related Costs) summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding.

ISSUED BY ORDER OF THE COMMISSION.

This the 31st day of March, 2021.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

Commissioner ToNola D. Brown-Bland dissents in part.
Commissioner Daniel G. Clodfelter dissents in part.
Commissioner Floyd B. McKissick, Jr., concurs in part and dissents in part.

DOCKET NO. E-7, SUB 1187
DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214

Commissioner ToNola D. Brown-Bland, dissenting in part:

I respectfully dissent from the Commission's decision to allow the Company to defer the capital costs of eight programs associated with GIP investments and to accept and approve the Second Partial Stipulation as it relates to said investments.

In my opinion, the majority decision on GIP cost deferral is contrary to the ratemaking standards of N.C. Gen. Stat. § 62-133. Use of deferral accounting is generally outside the traditional principles set forth in N.C.G.S. § 62-133(b) and (c), and therefore can only be allowed pursuant to N.C.G.S. § 62-133(d). However, the greater weight of the record evidence compels the determination that the cost items for which deferral is sought – and agreed upon by fewer than all parties of record – are not so unusual, extraordinary, or complex that the Company should be granted an exception to seek recovery of costs outside of the ordinary ratemaking standards established by the General Assembly; nor has the majority made any such finding. I cannot agree that the parties' settlement of this issue overrides or obviates the Commission's duty to make the determinations that are *required* before deferral accounting can be authorized under Chapter 62 of the North Carolina Utilities Act. *State ex rel. Utils. Comm'n v. Stein,* 375 N.C. 870, 926, 851 S.E.2d 237, 273 (2020).

In N.C.G.S. § 62-133(d), the legislature saw fit to provide both consumers of public utility service and public utilities with a "'safety valve'" which permits the Commission to consider facts outside of those prescribed by the ordinary ratemaking standards when those standards "prove inadequate" to allow the Commission to meet its obligation to set just and reasonable rates. *Id.* at 925-26, 851 S.E.2d at 272-73. Our Supreme Court recently clarified, however, that § 62-133(d), the safety valve, is to be relied upon over § 62-133(b) and (c) only "in extraordinary instances in which the traditional ratemaking standards set forth in N.C.G.S. § 62-133 are insufficient." *Id*. That is to say, N.C.G.S. § 62-133(d) is not to be exercised routinely.

To the contrary, "N.C.G.S. § 62-133(d) [does] not allow the Commission to . . . ignore the ordinary ratemaking standards set out elsewhere in N.C.G.S. § 62-133" where use of those principles allows for the establishment of just and reasonable rates. *Id.* at 926, 851 S.E.2d at 273. The "safety valve" is just that, and cannot be applied absent specific determinations of "unusual, extraordinary, or complex circumstances" unable to be addressed by traditional ratemaking standards. In relying on the safety valve, the Commission must reasonably conclude that such circumstances justify a departure from traditional standards, determine that the facts establishing those circumstances must be considered in order to set just and reasonable rates, and provide sufficient explanation as to why divergence from traditional standards is appropriate. *Id.* Such determinations and conclusions are decidedly absent from the majority decision.

In practice, the Commission has long applied virtually the same factors articulated by the Supreme Court in *Stein* before exercising its discretion pursuant to § 62-133(d) when allowing public utilities to recover costs using deferral accounting. The Commission has repeatedly stated that deferral accounting is the exception to the general rule that costs should be recovered from ratepayers and applied to or matched with revenues received during the same time period they were incurred; is contrary to the rule; should be used sparingly; and is not favored as it provides for the future recovery of costs for utility services provided to ratepayers in the past. *See* Order Approving Deferral Accounting with Conditions, *Petition of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred*, No. E-7, Sub 874, at 24-25 (N.C.U.C. Mar. 31, 2009).[1] As a result, the Commission consistently requires utilities requesting deferral treatment to make a clear and convincing showing that the costs proposed for deferral are of an unusual or an extraordinary nature or type and that, absent deferral, the requesting utility would experience a negative material impact on its financial condition. *Id.* This requirement ordinarily demands a showing that such costs represent significant, considerably complex, non-routine investments that were unanticipated or beyond the utility's ability to control or plan for the timing of incurring the costs. *See* Order Granting Partial Rate Increase, *Application by Carolina Water Service, Inc. of North Carolina for Authority to Adjust and Increase Rates for Water and Sewer*, Docket No. W-354, Sub 364, at 42-43 (N.C.U.C. March 31, 2020). If the cost items sought to be deferred are not found to be unusual or extraordinary, such determination is dispositive and the materiality of the impact of the costs on the financial condition of the utility is not reached. *See* Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11 (N.C.U.C. Mar. 29, 2016).

In this case, as in DEC's last rate case, the items proposed for deferral fail the unusual and extraordinary inquiry. DEC previously proposed to recover costs using deferral accounting for a modernization project it called Power Forward. I agree with Commissioner Clodfelter that GIP as presented in the instant case is primarily a subset, or a whittled down, more compact version, of Power Forward — in its scope, size, and costs. The eight GIP programs that the Public Staff and DEC stipulate as appropriate for

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[1] *See also* Order Approving Partial Settlement Agreement and Stipulation, Deciding Contested Issues, Granting Partial Rate Increase, and Requiring Customer Notice, *Application of Aqua North Carolina, Inc. to Adjust and Increase All rates for Water and Sewer Utility Service,* No. W-218, Sub 526, at 41-47, 136-37 (N.C.U.C. October 26, 2020); Order Allowing Deferral Accounting, *Transfer of Certificates of Pub. Convenience and Necessity and Ownership Interests in Generating Facilities from Duke Energy Carolinas, LLC, to Northbrook Carolina Hydro II, LLC, and Northbrook Tuxedo, LLC*, No. E-7, Sub 1181, at 16-18 (N.C.U.C. June 5, 2019); Order Approving Partial Settlement Agreement and Stipulation, Granting Partial Rate Increase, and Requiring Customer Notice, *Application by Aqua N.C., Inc., for Authority to Adjust and Increase Rates*, No. W-218, Sub 497, at 50 (N.C.U.C. Dec. 18, 2018); Order Approving Amended Schedule NS and Denying Deferral Accounting, *Application by Virginia Elec. & Power Co., d/b/a Dominion N.C. Power, for Approval of Amended Schedule NS*, No. E-22, Sub 517, at 11-12 (N.C.U.C. Mar. 29, 2016); Order Approving Deferred Accounting Treatment, *Request by Pub. Serv. Co. of N.C., Inc., for Deferred Accounting Treatment Related to Year 2000 Conversion Costs*, No. G-5, Sub 369, 3-4 (N.C.U.C. Apr. 29, 1997), *aff'd*, Order on Reconsideration (N.C.U.C. June 12, 1997).

deferral treatment are not at all extraordinary or unusual. Neither the GIP programs nor the reasons proffered for their need, as was the case with the programs in Power Forward, are unique or extraordinary to DEC or North Carolina. Rather the GIP programs are update, upgrade, and modernization programs, required of the Company to maintain the electrical distribution system and improve reliability, and are part of the routine, ordinary business of being a vertically integrated electricity provider. Without such programs the electric utility would not be providing quality service.

Further, these requirements are not new to the industry, and it cannot be said that the Company was unaware and unable to plan and time the recovery of the modernization projects approved by the Commission as part of GIP. Instead, a quick review of DEC's parent company's Annual Reports reveals that the Company and its parent have been discussing and planning for grid modification initiatives for a long time. Unlike a catastrophic storm that develops with little notice or warning, the need for grid modification is such a routine circumstance that the Company has openly discussed its intended plans for over ten years. In 2010, the parent company discussed graduating its grid from analog to digital and adding two-way communications capabilities to its system to improve reliability and better serve customers. Moreover, as noted by Commissioner Clodfelter, the Company has been investing in grid modification and some of the proposed GIP programs over several years, further highlighting that this work is a regular part of the Company business and, more importantly, that traditional ratemaking procedures have been adequate. To this day, all decisions as to timing, pace, and amount of spending on grid modification have been largely within the Company's control — again, undermining any finding of extraordinary circumstances that might justify deferral accounting as a means of cost recovery for GIP.

I do not disagree with the proposition that GIP will provide benefits or that the Company's initial GIP proposal has been narrowed, focused, and vetted by stakeholders, including the Public Staff, who have worked together and invested time in coming to agreement and refining DEC's GIP proposals. I also believe that it is wise, given so much uncertainty around the cost estimates for GIP, that the Commission is limiting costs and that the Public Staff will work with the Company to file reports and cost trackers on various details of GIP progress. Yet, none of these considerations establishes that GIP is extraordinary or unusual such that the Company should be allowed to depart from the ordinary ratemaking procedures in § 62-133.

It is my further opinion that parties in this proceeding have misconstrued the language in the Commission's opinion in the 2018 DEC Rate Order. There, the Commission stated the following:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, with respect to demonstrated Power Forward costs incurred by DEC prior to the test year in its next case, the Commission authorizes expedited consideration, and to the extent permissible, reliance on leniency in imposing the "extraordinary expenditure" test.

2018 DEC Rate Order, at 149. This language was not meant to signal any change to the Commission's historical test for deferral accounting. Rather, it was a suggestion that the Commission had that option if it wanted to make a change to the test specific to a request for deferral being considered as part of a general rate case. No such change was made in that Order and no such change has been made in this Order either. The test remains unchanged and still requires a finding of extraordinary and unusual circumstances. Indeed, given the *Stein* decision it is not clear that the Commission *could* craft a test without such a requirement even had it wanted.

Moreover, the second sentence in the passage above relates to a deferral request made outside a general rate case. It is not meant to convey the demise of the historical primary focus of the deferral test, *i.e.*, the extraordinary and unusual circumstance. *See also id.* (explaining unusual or extraordinary determination is primary hurdle for deferral approval). Rather, it addresses the secondary materiality/magnitude aspect of the test in the event that DEC were to seek deferral prior to, and outside of, a general rate case. Had this circumstance occurred, the leniency, the determination of which was not ceded to the Public Staff, was directed only at the "extraordinary *expenditure"* threshold — not the extraordinary or unusual circumstance aspect of the test, which is required by the Supreme Court in *Stein* for the exercise of the Commission's authority pursuant to § 62-133(d).

Finally, like all utilities whose rates for service are set by the Commission, DEC abhors regulatory lag and has from time to time made attempts to eliminate or reduce it by use of the deferral mechanism. However, some lag is an inherent part of the statutory ratemaking process in North Carolina – and has been for decades. While regulatory lag in rates offers some positive aspects to customers – e.g., serving as incentive for cost effective and efficient management of the utility and also serving as a guard against waste and inefficiency – it is understandable that utilities see it as a challenge. If regulatory lag is indeed the driving force behind the request for deferral treatment of GIP costs, the appropriate solution is legislative relief. The Commission should not strain the bounds of its authority to exercise use of a deferral mechanism where the legislature did not intend it to be used.

For these reasons I respectfully dissent.

/s/ Commissioner ToNola D. Brown-Bland
Commissioner ToNola D. Brown-Bland

DOCKET NO. E-7, SUB 1187
DOCKET NO. E-7, SUB 1213
DOCKET NO E-7, SUB 1214

Commissioner Daniel G. Clodfelter, dissenting in part:

I differ from the Commission Opinion on three points and therefore write separately to explain my reasons for doing so.

I. Deferral of Grid Improvement Plan Capital Costs

Deferral accounting is an exception to the basic principle embodied in N.C.G.S. §62-133 that costs are to be allocated and charged to the revenues received in the period during which expenditures were incurred. *State ex rel. Utilities Commission v. Edmisten,* 291 N.C. 451, 468-70, 232 S.E.2d 184, 194-96; *State ex rel. Utilities Commission v. Stein,* Nos. 271A18 and 4901A18, 2020 N.C. LEXIS 1058 (N.C. Dec. 11, 2020), at Slip Opinion 79. For this reason the Commission has established a clear standard for granting deferral accounting treatment. I believe the Commission addresses this standard only in the most cursory fashion and does not properly consider its application to this case.[1] As recently as its March 31, 2020 Order Granting Partial Rate Increase and Requiring Customer Notice in Docket No. W-354, Sub 363 (the CWSNC Order) the Commission reiterated that deferral accounting should be used sparingly and as an exception to the general rule that all items of revenue and costs germane to the ratemaking and cost-recovery process should be examined in their totality in determining the appropriateness of a utility's rates and charges. Paraphrasing from the CWSNC Order, deferral is not favored in part because it typically provides for the future recovery of costs for utility services that were provided to ratepayers in the past. The Commission has found that an exception can be made when reasonable and prudently incurred costs are unusual or extraordinary, in some instances because they were unexpected, and when they are of a magnitude that would result in a material impact on the utility's financial position in the absence of an ability to recover those costs from revenues in future periods. In applying this test the Commission has disfavored deferral treatment for expenditures that are planned or whose timing and amount are under the control of the utility. In this instance the record is clear that the costs for which deferral accounting treatment is requested are among a larger group of ongoing programs to modernize and upgrade DEC's transmission and distribution systems, many of which were commenced and well under way well before deferral accounting was requested in this case, all of which are completely under the Company's control, and, none of which, singly or in combination, present any significant threat to the utility's financial condition or its ability to earn its allowed rate of return.

[1] The discussion of the standard for deferral accounting in the Commission's opinion at page 139 is limited to noting that in the Sub 1146 Order the Commission stated that deferral accounting could be granted under different parameters in a general rate case than when the request was made outside a general rate case. But the opinion does not attempt to articulate what those "different parameters" are or might be. And, as noted elsewhere in this dissent, the Commission has regularly applied its established standard *in general rate cases,* including in Docket No. E-7 sub 1146 and the other Commission decisions cited and quoted in this dissent.

Because deferral accounting is a departure from the basic ratemaking structure set forth in N.C.G.S. § 62-133(a)-(c), it is pertinent to consider the Supreme Court's recent discussion in *Stein*. There the Court set forth four factors that govern the Commission's reliance upon its authority under N.C.G.S. § 62-133(d) to supplement, modify, or depart from the basic ratemaking structure established in §§ 62-133(a)-(c). The four factors identified by the Court in its opinion are essentially a restatement of the Commission's traditional two-prong test for accounting deferrals:

> …we hold that the Commission may employ N.C.G.S. § 62-133(d) in situations involving (1) unusual, extraordinary, or complex circumstances that are not adequately addressed in the traditional ratemaking procedures set out in N.C.G.S. § 62-133; (2) in which the Commission reasonably concludes that these circumstances justify a departure from the ordinary ratemaking standards set out in N.C.G.S. § 62-133; (3) determines that a consideration of these "other facts" is necessary to allow the Commission to fix rates that are just and reasonable to both the utility and its customers; and (4) makes sufficient findings of fact and conclusions of law supported by substantial evidence in light of the whole record explaining why a divergence from the usual ratemaking standards would be appropriate and why the approach that the Commission has adopted would be just and reasonable to both utilities and their customers.

Slip Opinion at 87-88.

The record in this case plainly establishes that DEC does not need accounting deferral treatment to enable it to undertake and move ahead with its grid improvement initiatives (the Grid Improvement Plan or, sometimes, GIP). Public Staff witnesses testified that at the time of this general rate case and without any inducement or protection under a deferral accounting order the Company had already commenced work on twelve of the GIP programs, that it spent about $52 million on those programs during the 2018 test year, and that it had spent another $273 million during 2019.[2] *Tr. vol. 17, 313.* During the update period of February through May 2020, DEC completed and placed in service another $34.7 million of investments in the various GIP programs.[3] *Tr. vol. 22, 61.* In fact DEC's own evidence was that spending on the self-optimizing grid program was outpacing its staff's ability to implement attendant computer programming changes needed to enable complete functionality of those investments, leading to delays in full implementation of some of the system upgrades. *Tr. vol. 29 addendum, 7-8.* Given these facts I am compelled to conclude that the GIP investments are very far from being extraordinary, unusual, or unanticipated; they are instead well-thought out, planned, and executed upgrades and improvements to enhance the performance and the reliability of

[2] Except where otherwise noted, all figures are on a total system basis.

[3] This total of approximately $360 million spent over a period of approximately two and one-half years *without* the benefit of any deferral accounting treatment should be compared to the approximately $800 in GIP program expenditures over the two and one-half years from June 2020 through December 2022 for which the Commission finds deferral treatment to be necessary and appropriate.

the Company's transmission and distribution systems. Maintaining, protecting, adapting, and enhancing reliability and performance of the electric grid are core obligations of any electric utility.

The Company contends that all these investments, and those it wishes to make in the future, are necessary and indeed essential to respond to changes and challenges arising from such things as the deployment of distributed generation and other new grid-edge technologies and from increasing security concerns about cyberattacks on businesses and infrastructure such as the electrical grid. The fact that these improvements may be sound and even necessary does not, however, meet the Commission's standard for deferral treatment. The Company attempted to distinguish its GIP investments from other ongoing spending to upgrade equipment and facilities with newer, more efficient and effective replacements by relying on seven so-called "megatrends." These megatrends, however, are nothing more than general features of North Carolina's evolving demography and economy or else they arise from technological innovations that are affecting many sectors of modern life and do not uniquely affect the electric power industry. They have been at work for many years and are neither accidental, sudden, nor unforeseen. The difficulty with arguing from these megatrends to justify special ratemaking treatment for the company's GIP spending is that the argument simply proves far too much. Virtually every aspect of the Company's traditional model is being affected in some way by one or more of these megatrends. If the megatrends justify special ratemaking treatment for the eight specific GIP programs singled out in the Second Partial Stipulation they very likely could justify similar treatment for all other portions of the Grid Improvement Plan and, for that matter, virtually every new investment the Company wishes to undertake.

Rather than being extraordinarily or unusual I would find DEC's GIP programs to be more analogous to the automated meter reading (AMR) installations for which Carolina Water Service of North Carolina (CWSNC) sought deferral accounting in Docket No. W-354, Sub 364. Both involve the deployment of new technologies that promise substantial efficiencies and new capabilities for the utilities and resulting benefits for customers. In the CWSNC Order the Commission found that CWSNC's meter replacements had been on-going for several years and were anticipated to extend several more years into the future. In that case as in this one, the utility requested deferral accounting to mitigate the effect of regulatory lag on earned returns. The Commission rejected CWSNC's request, noting that the timing of meter replacements was entirely within the control of the Company. The fact that CWSNC's AMR investments spanned many years contributed to the Commission's determination that the investments were part of the regular business of adapting and updating the utility's systems to meet the most up-to-date standards and technologies. The fact that they sought to adopt a new technology and realize significant system benefits enabled by that new technology did not win the day for deferral treatment. The DEC investments presently before the Commission also span many years, some programs starting as early as 2018 and some extending beyond 2022, based on DEC's cost-benefit analyses. Several of them, such as the replacement of oil-filled hydraulic reclosers with remotely operated digital reclosing devices, the replacement of single-use fuses with automated reset fuses, and the replacement of electromechanical relays with remotely operated digital relays are virtually indistinguishable in substance from CWSNC's replacement of manually read water meters with AMR meters.[4]

In this instance several parties who support the Company's deferral accounting request, notably the Public staff, rely heavily, in fact almost entirely, on inferences they draw from the Commission's last DEC general rate order issued June 22, 2018, in Docket No. E-7, Sub 1146 (the Sub 1146 Order). In that case DEC petitioned for creation of an annual revenue rider, or alternatively, to obtain deferral accounting treatment for a set of grid modernization programs it then referred to as Power Forward.[5] In its Sub 1146 Order the Commission found that DEC failed to show that Power Forward costs qualified for deferral accounting treatment. The Sub 1146 Order stated:

> …The Commission finds that DEC has not satisfied the criteria for deferral accounting…. In order for the Commission to grant a request for deferral accounting treatment, the utility first must show that the cost items at issue are adequately extraordinary, in both type of expenditure and in magnitude, to be considered for deferral. Second, the utility has to show that the effect of not deferring such cost items would significantly affect the utility's earned returns on common equity. Although it was uncontested … that DEC's planned Power Forward spend is extraordinary in magnitude, the Commission is unpersuaded [that all of the programs] are unique or extraordinary… DEC [also] failed to show that the effect of not deferring [the] costs would significantly affect its earned returns on common equity.

Sub 1146 Order, at 148.

In the Sub 1146 Order the Commission directed DEC to collaborate with stakeholders to address the myriad issues that had been raised about Power Forward in that rate case. In addition, the Commission stated:

> The Commission can authorize a test for approving a deferral within a general rate case with parameters different from those to be applied in other contexts. Consequently, *with respect to demonstrated Power Forward costs*

[4] One of the eight GIP programs included in the Second Partial Stipulation involves cybersecurity. As the Commission's opinion notes, DEC witness Oliver testified that these elements of the GIP are essentially the same as those DEC has been funding in the past, only the amount of spending will be increased. *Consolidated Tr. vol. 5, p. 39.* With respect to the cybersecurity programs I also note that the Company has obtained a FERC order permitting it to aggregate its expenditures into a single composite project eligible for AFUDC treatment, thereby allowing the Company to continue to accrue AFUDC until the last component element of its cybersecurity project is placed into service. FERC Docket No. AC19-75-000(Dec. 19, 2019). It is not at all clear how this treatment relates to the deferral accounting treatment requested in this case or why if AFUDC treatment is available for these cybersecurity programs there would be any need for deferral accounting treatment for the cybersecurity programs at all.

[5] The specific programs for which deferral accounting treatment is sought in this case is a subset of the larger set of what DEC refers to as its Grid Improvement Plan, which in turn is itself a substantially modified version - both in scope and magnitude and as to its elements - of the earlier Power Forward initiative.

> *incurred by DEC prior to the test year in its next case*, the Commission authorizes expedited consideration, and *to the extent permissible*, reliance on leniency in imposing the "extraordinary expenditure" test.

Id., at 149 (Emphasis added).

Public Staff witness Maness interpreted the Sub 1146 Order to mean that the Commission is prepared to show leniency as to the financial impact of the Company's request in the instant rate case. That interpretation was not the Commission's intent and it does not comport with the actual language used by the Commission. Rather, the quoted language from the Sub 1146 Order refers to a scenario that did not occur, one in which DEC incurred grid modernization costs before the test year in the current case and requested deferral treatment for those costs in the interim period and outside the parameters of a general rate case. Had that occurred, the Commission was prepared to consider the request in an expedited fashion, outside a general rate case, and was prepared to be lenient in imposing the extraordinary expenditure test, especially if DEC's collaboration with the parties had produced consensus as to the programs whose costs would be deferred. That is simply not the situation now presented to the Commission.

Moreover, the language from the Sub 146 Order relied upon by the Public Staff was directed to the first prong of the Commission's deferral accounting standard – that the expenditures be unusual or extraordinary in type and magnitude – and not to the second prong of that standard. On that issue I believe the pertinent language from the Sub 146 Order is the following statement:

> With respect to deferral, the Commission acknowledges that, irrespective of its determination not to defer specific costs in this case, the Company may seek deferral at a later time outside of the general rate case test year context to preserve the Company's opportunity to recover costs, to the extent not incurred during a test period. In that regard, were the Company in the future before filing its next rate case to request a deferral outside a test year *and meet the test of economic harm,* the Commission is willing to entertain a requested deferral for Power Forward, as opposed to customary spend, costs.

Id., at 149 (emphasis added).

In his direct testimony Public Staff witness Maness stated that the Public Staff would not object if the Commission determined that the ROE impacts from the GIP programs covered by the Second Partial Settlement fall within the range of leniency that the Commission intended in the Sub 1146 Order. *Tr. vol. 20, 539.* Strikingly, however, in response to questions from Commissioner Brown-Bland, witness Maness confessed that absent the quoted language from the Sub 1146 Order he could not conclude that the GIP investments proposed for deferral treatment met the financial impact prong of the Commission's standard. *Tr. vol. 7, p. 32; Consolidated Tr., vol. 7, 35; see also*

Commission Opinion p. 122.[6] DEC witness Oliver confirmed that if the Commission did not grant deferral accounting treatment for the proposed GIP programs, the Company nevertheless would continue to implement them, managing and adjusting to accommodate available resources and timetables in order to do so. *Consolidated Tr. vol. 6, 56.*

Leaving aside the Commission's two-prong test for deferral treatment and the Supreme Court's *Stein* factors defining the Commission's authority to depart from traditional ratemaking principles, there are other features of the Second Partial Stipulation's provisions dealing with GIP programs I find unsettling. One of those involves what exactly it is that the parties are asking from the Commission. Deferral accounting treatment for expenditures made in connection with specific GIP programs is certainly being sought, but there is also something more. DEC witness McManeus testified that it is important for the Commission to make clear that the Commission believes the GIP programs are appropriate undertakings and that the costs of such program can ultimately be recovered from customers, assuming they are found to be reasonable in amount. *Consolidated Tr. vol. 9, 24.* To that end the Second Partial Stipulation of Settlement contains the following paragraph:

> The Stipulating Parties' agreement regarding deferral treatment of GIP costs constitutes only approval of the decision to incur GIP program costs. The Public Staff reserves the right to review costs for reasonableness and prudence.

Second Partial Stipulation § IV.D.

Under questioning from Commissioners neither the Company nor the Public Staff witnesses were able to give completely clear meaning to this provision, seeming to contend that acceptance of this provision commits the Commission to allowing cost recovery for GIP program expenditures in future rate cases while at the same time preserving the Commission's full review of GIP spending under the traditional "prudence" standard. As I interpret it, the Company is seeking prior Commission approval of a list of loosely related programs, a practice this Commission seldom follows outside certificate of public convenience and necessity proceedings.[7] Some of those programs involve

[6] Even if the Sub 1146 Order were interpreted such that "leniency" is taken to refer to both prongs of the deferral standard, not just the "extraordinary expenditure" prong, it should be noted that the Commission qualified leniency with the phrase "to the extent permissible." The outer boundaries of what is "permissible" are not, and likely could not be, established with certainty. But a virtual abandonment of the requirement that the utility show substantial financial harm is not, I think, within those boundaries. In this regard I note that N.C.G.S. § 62-133(b)(1)a. authorizes the Commission to approve inclusion of construction work in progress in rate base, a mechanism to address regulatory lag similar in some ways to deferral accounting, when the Commission finds such use to be in the public interest "and necessary to the financial stability of the utility in question."

[7] Indeed, as to those elements of the GIP that involve investment in utility plant and equipment, as opposed to expenditures made on such things as planning, operational design and operating management of the grid, if those investments are indeed so extraordinary and unusual as is contended, one may well ask why they are not subject to the certificate of public convenience and necessity requirement set forth in N.C.G.S. 62-110(a), which requires a certificate before construction or operation of "any public utility plant or system," except where such construction or operation occurs in the "ordinary course of business."

primarily operational and business process changes, such as the Integrated Systems Operations Plan, while others involve investments in new hardware and physical infrastructure. The Company did not articulate any set of unifying principles – aside from referring to the so-called "megatrends" – that bring these disparate programs into a single integrated whole. The proposed bifurcated review, which is what I believe the quoted provision is attempting to accomplish, deprives the Commission of the ability when all costs have been incurred and all benefits have been have realized or set in motion to judge whether or not the investment was warranted in the first instance. Although the Second Partial Stipulation contemplates ongoing review of GIP program spending by the Public Staff, it does not set forth any clear or measurable performance goals or targets that must be met in order ultimately for cost recovery to be allowed. According to the Second Partial Stipulation the Public Staff's review will include an evaluation of actual benefits realized compared to anticipated or expected benefits. What will be the way forward if the Public Staff should conclude that expected benefits failed to materialize in any significant degree or were wholly or very largely offset by unexpected or additional costs? In such a case will the quoted provision from the Second Partial Stipulation permit or will it not permit a determination that cost recovery should be denied altogether? Unlike a majority of the Commission, I do not believe an aggregate spending cap on the amount of expenditures for which deferral treatment is allowed is an adequate substitute for clear and measurable performance goals or targets that must be met in order for cost recovery to be allowed.[8]

A second unsettling feature of the Second Partial Stipulation's treatment of the GIP programs involves the increasing tendency for regulated utilities to attempt to string together a series of small scale investments in order to craft some composite whole that can be offered up and proposed for deferral accounting treatment. The evolution first from Power Forward, then to the Grid Improvement Plan, then to a series of multiple, only partially overlapping, settlements between DEC and various individual parties to this proceeding about which GIP programs those parties would support, finally culminating in the Second Partial Stipulation with the Public Staff is a good illustration of the potential problems with this approach to solving the problem of regulatory lag.

In a recent general rate case involving Aqua North Carolina, Inc. (Aqua), Public Staff witnesses expressed reservations about a deferral accounting request that involved the aggregation of many unrelated projects. (*See* Joint Testimony of Windley E. Henry and Charles M. Junes dated May 26, 2020, in Docket No. W-218, Sub 526.) These witnesses testified that Aqua's deferral request was based on "the novel argument that the projects and related costs for which it seeks deferral accounting treatment should be considered not on an individual basis, but in the aggregate." I believe the same could be said of DEC's GIP request in this case. I am concerned with the large number and variety of programs that DEC has included under the GIP umbrella, with cost estimates that could vary by as much as 30 percent, and that contains many investment types that overlap

[8] The "loose approval" treatment afforded here for the proposed GIP programs can be contrasted with the carefully structured provisions in N.C.G.S. § 62-110.1 governing certificates of public convenience and necessity for new generating facilities, which include several clauses authorizing the Commission to modify, revoke, or cancel a previously granted CPCN.

with customary maintenance, repair, and upgrade expenditures. It will, I believe, become increasingly difficult for the Commission to apply the "extraordinary" or "unusual" prong of its established deferral accounting treatment with any degree of integrity or consistency if this practice of aggregating expenditures becomes well established, especially if, as occurred in this case, that aggregate is arrived at by a process of negotiation and settlement among contending stakeholders.

A third feature that gives me pause concerns the future rate impacts of the Commission's approval of the Second Partial Stipulation. It is true that the decision to approve deferral accounting treatment for the GIP program expenditures included in the Second Partial Stipulation has no impact on the rates established in the present case. I cannot ignore, however, the implications of this request for future rate cases. The Company supports its case for the GIP investments by offering cost-benefit analyses that, the Company contends, show strong positive economic benefits from those investments. These analyses covered only some components and subprograms within the larger GIP effort, and they were strongly criticized by several intervenor witnesses as being based on studies or data that were out-of-date, were not well-tailored to the demographics and economy of North Carolina, or were otherwise deficient or flawed in various respects. Even if all those criticisms are valid, it nonetheless remains true that the Company and the contending intervenor adversaries did not disagree on either the directionality or the order of magnitude of one unmistakable feature of the Company's cost-benefit studies. The economic benefits disclosed by those studies center on improvements to service reliability, and they overwhelmingly flow to the benefit of the industrial and commercial customer classes. See *Commission Opinion p. 122.* Yet based on the Company's analysis filed in this case the revenue requirement and resulting rate impact from the GIP programs will fall most heavily on the residential customer class. See *Commission Opinion p. 133.* For me this is a pertinent point.[9]

Witnesses for the Company and supporters of the GIP contended that the Commission should keep separate the present question - whether to grant permission to proceed with the GIP investments and grant deferral accounting treatment - from the question in future rate cases concerning how GIP program costs should be assigned to the different customer classes and, accordingly, reflected in rates. In the face of the extensive evidence presented in this case concerning problems of affordability of electric service, especially for low-income and unemployed North Carolinians and for many small businesses bearing the burden of a year of COVID-19 disruptions, I simply cannot perform this feat. If complications concerning the differential future rate impacts on different customer classes are staring at us from the end of the road, I am not comfortable pre-approving the GIP programs and granting them special ratemaking treatment without

[9] Certain witnesses contended that it is not appropriate to consider the proportionality of the assignment of costs relative to the realization of benefits among the various rate classes. I commend to those witnesses Part I, Chapter 5 of Professor Bonbright's treatise, *Principles of Public Utility Regulation* (1960), where he discusses the use of the concepts of "value" and "benefit" in ratemaking. Summarizing the different theories and ways in which those concepts come into play, he observes" "…[I]n actual rate cases the cost [of service] principle is always given modified interpretation which, while not converting it into a value principle, takes indirect account of the effectiveness of the cost incurrence in contributing to the benefit of the consumers." *Id.* at p. 91.

fully considering how the Commission will manage those complications when they materialize in future rate cases? The better course would be to evaluate actual GIP expenditures made by the Company and actual results achieved for customers in the context of all other issues and decisions that culminate in the setting of just and reasonable rates in a future general rate case. While the Commission's decision to place a cap on the total GIP expenditures eligible for accounting deferral is a useful step, I believe it is an inadequate substitute for the kinds of tools the Commission must have in order to properly grant pre-approval of the kinds of forward-looking expenditures such as the Company's proposed GIP investments.

Although in the end I dissent from the Commission's decision to grant deferral accounting treatment for elements of the proposed GIP, I am nonetheless conflicted about doing so. Increasingly, our present statutes governing ratemaking are proving to be poorly suited to address the types of investments that utilities are making and must continue to make in order to transition the electricity grid to the new world of distributed generation from renewables, non-wires solutions to grid reliability and capacity issues, and the two-way power flows that result from these first two trends, not to mention looming electrification of the transportation and real estate sectors and new challenges to grid reliability and resiliency due to cyberattacks and severe weather events. The fundamental paradigm by which rates are derived from examination of historic expenditures was adequate for a time when the electricity system was more stable and when major capital investments were largely centered on the addition of new centralized generating plants built to accommodate increases in aggregate system load. That paradigm does not work well now.

Even under the traditional ratemaking paradigm the General Assembly has shown an understanding of the need for tools that would enable what I would call "forward-looking" or, alternatively, "rapid response" ratemaking treatment in instances involving major capital expenditures or concerns about regulatory lag. In 2013 the General Assembly enacted N.C.G.S. § 62-133.12 to alleviate the effects of regulatory lag by allowing for recovery outside a general rate case of some portion of incremental depreciation expense and capital costs for eligible water and wastewater infrastructure projects that are placed into service between general rate cases. I believe the same recognition underpins N.C.G.S. § §62-133(b)(1)a. and 62-133.1(b)(1)b., which establish the Commission's authority, under the circumstances and conditions spelled out in those statutes, to include in rate base construction work in progress, and also N.C.G.S. § 62-110.7, which governs advance review and approval of nuclear power plant development. To date, however, for investments of the type exemplified by the GIP programs, no such special statutory treatment has been enacted, and thus the Commission is left to operate within the limits established by N.C.G.S. § 62-133(a)-(c), supplemented by § 62-133(d) as interpreted by the Supreme Court in *Stein.*

I wholeheartedly support efforts to change the existing ratemaking paradigm embodied in Chapter 62, and I was encouraged by the progress made in the consideration of SB 559 in the 2019-2020 session of the General Assembly. Though that legislation ultimately was not enacted, it will not be the last such effort. Recommendations coming from stakeholder working groups convened to flesh out the Clean Energy Plan developed in response to Executive Order 80 contain a number of options and possible changes to the General Statutes that could, if adopted, enable the Commission better to manage approval, oversight, and cost recovery for initiatives such as DEC's Grid Improvement Plan.[10] Unfortunately, though, for now we must decide proceedings before us following the statutes we have. The Commission's decision is ultimately based not on substantial evidence that is material and sufficient under current law and precedent but instead on a wish and a hope – a wish that the Commission had the kind of authority I believe is essential for the future and a hope that the General Assembly will, even if after the fact as far as the present proceeding goes, take action that validates the policy rationale for the decision in this case. I share both that wish and hope, but I am constrained by the tools that we have been given by the General Assembly until they are changed.

I differ from the majority in that I do not believe a partial settlement of disputed issues, even more so an agreement by fewer than all parties, can substitute for the Commission's lack of authority to engage in "forward looking" ratemaking, that it can override or displace the Commission's existing standard for deferral accounting treatment, nor that it can rectify the deficiencies in the evidence submitted to the Commission under its traditional test for an accounting deferral order. While settlements are certainly to be encouraged, I believe the Commissions' deference to the Second Partial Stipulation in this instance fails to comply with the requirement that the Commission exercise its own independent judgment with respect to the matters embraced in the settlement. This is especially troubling in that the settlement overrides a Commission standard that is to be used sparingly and whose use is to be considered an exception to general ratemaking principles. If parties come to know and understand that by settlement they can circumvent the Commission's standard, then what will be left of the notions of "sparingly" or "exceptional"? With respect to the Commission's decision granting deferral accounting treatment for certain of the company's GIP expenditures I must therefore dissent.

II. Coal Ash Disposal and Groundwater Remediation Costs

Though I endorse much of the Commission's discussion of the proposed settlement relating to coal ash disposal and remediation costs, I cannot go the full distance. Pending before the Commission now are two matters only – first, a decision establishing rates in this proceeding and second, a decision on remand from the Supreme Court in Docket No. E-7 sub 1146. I agree with the Commission majority that those portions of the CCR Settlement that address the two pending matters are appropriate and would produce rates that are fair and reasonable to the company and to ratepayers. In arriving at this conclusion I have relied on the combined effect of the settlement of the case on remand and the settlement of the current proceeding. Considering them separately and individually, however, I would not reach the same result. For reasons

[10] See North Carolina Energy Regulatory Process – In Fulfillment of the North Carolina Clean Energy Plan B-1 Recommendation, December 22, 2020 Summary Report and Compilation of Outputs (https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/2020-NERP-Final-Report.pdf).

discussed in my dissenting opinion in Docket No. E-7 sub 1146 I do not consider the result in that case to be one that yielded just and reasonable rates, and the proposed CCR Settlement would reaffirm and leave unchanged that result. At the same time, however, the CCR Settlement would impose a greater reduction in the cost recovery request for ash basin closure and groundwater remediation expenditures in this case than I was prepared to impose, based upon the evidence offered in this case and the specific facts concerning the particular expenditures for which cost recovery is sought in this case.

I am unclear as to exactly what position the Commission is taking with respect to the forward-looking provisions of the CCR Settlement. *See Commission Opinion, Findings of Fact 23, 24 and 26.* Aside from authorizing the Company to continue to defer ash basin closure and remediation expenditures in the same manner as was approved for the costs in this case and those in Docket No. E-7 sub 1146, at this point I would take no position on those portions of the CCR Settlement that speak to the treatment of ash basin closure and groundwater remediation costs in future general rate cases. Those matters are not now at issue and thus are not before the Commission. Whether the financial terms the settling parties propose be applied to cost recovery requests in future rate cases will produce just and reasonable rates is, I believe, a question that can only be decided when the Commission has before it all the facts and circumstances of those future cases.

Finally, while I join in the Commission's directive, *Commission Opinion p. 75,* that the Company consider in its next general rate case the option of including in base rates a normalized allowance for ongoing coal ash expenditures, I would also have been prepared to go further and adopt such a cost recovery mechanism in the present case for all or some of the company's ongoing costs. When this mechanism was suggested by the Company in Docket No. E-7 sub 1146, it was rejected by the Commission. Two fundamental developments since that time have made the option viable and even, in my view, preferable to what the Commission and the parties have called the "spend-defer-recover" method employed to date. The Company's settlement with the Department of Environmental Quality means that from this point the nature and scope of the tasks that the Company will be required to perform in order to close the remaining ash impoundments and remediate detected groundwater contamination are no longer subject to regulatory uncertainty and litigation. They can be predicted and planned with a much greater degree of accuracy than was possible in 2017. Additionally, the Company has now substantially completed or is well advanced toward completing impoundment closure activities at its Dan River, Riverbend, and Buck facilities and has thereby gained valuable experience in forecasting the costs it may reasonably expect to incur to perform various closure activities. Because this cost recovery option would provide the company consistent, predictable current cash flow to fund impoundment closure activities, not requiring it to tap its credit facilities or use shareholder capital, and because it would do so at lower cost to ratepayers, I believe it to be the superior method for achieving just and reasonable rates.

III. Cost Allocation Matters

Briefly, I note that my views on the appropriateness of using the single coincident peak method for allocating among customer classes the demand portion of production costs and of using the minimum system method for allocating a portion of distribution system costs on a per customer basis remain unchanged from my dissents in Docket Nos. E-2 sub 1142 and E-7 sub 1146. I believe these two cost allocation methodologies are flawed, and in the case of the so-called "minimum system" method they are increasingly being abandoned by regulatory commissions in favor of the "basic customer charge" method. In this case the Company was unable to produce any new, different, or more persuasive reasons for me to reconsider my prior positions. I am, however, hopeful that the two stakeholder forums initiated by the Commission's decision in this case – one intended to take a comprehensive review of matters of rate design and the other dealing with problems of affordability -- will permit a more extensive debate about how these flawed cost allocation methods help drive many of the problems that exist in current customer classifications and class rate designs and with respect to the affordability of service for low-income residential customers.

For the foregoing reasons and with respect to the issues discussed in this opinion, I dissent.

/s/ Daniel G. Clodfelter
Commissioner Daniel G. Clodfelter

DOCKET NO. E-7, SUB 1213
DOCKET NO. E-7, SUB 1214
DOCKET NO. E-7, SUB 1187

Commissioner Floyd B. McKissick, Jr., dissenting in part, and concurring, with an explanation:

Deferral of Grid Modernization Expenses

The majority has accepted the Second Partial Stipulation as it relates to eight separate projects which they are now collectively referring to as being part of a Grid Modernization Program. I must dissent on this issue. In my opinion, these projects fail to satisfy the four factors identified by the Supreme Court in *Stein*, which are substantially the same as the two-pronged test historically applied by the Commission for accounting deferrals. The Commission's acceptance of the Second Partial Stipulation in light of these circumstances has the potential to incentivize applicants in future cases where deferral treatment is sought to use the give and take of compromise to seek the deferral treatment of projects which would not otherwise meet or satisfy standards of the court or of this Commission. In addition, the Company commenced substantial work pursuant to its Grid Modernization Program before it sought deferral accounting treatment in this proceeding, and testimony provided by the Company's witnesses during the hearing clearly and unambiguously expressed an intent on the Company's behalf to carry out its Grid Modernization Program regardless of whether deferral accounting treatment was granted by the Commission in this proceeding.

Coal Ash Disposal

Concurrence with Explanation

After conducting a critical review of the CCR Settlement, I am persuaded that the give and take of the compromise process has resulted in an agreement between the parties to the stipulation, those parties being DEC, the Public Staff, the NC Attorney General's Office, and the Sierra Club to the issues set forth and agreed upon in the CCR Settlement Agreement. It is I believe uncontroverted, but nonetheless worth stating, that this agreement cannot legally bind other parties or intervenors in the future through the year 2030 that were not parties to the agreement. Therefore, intervenors in the future that were not parties to the CCR Settlement would be free to raise issues or contentions they deem relevant and appropriate relating to these issues. Likewise, future Commissions would have a duty and responsibility to hear and receive evidence on the issues at an appropriate time, including evidence relating to the issues agreed upon by the stipulating parties in the CCR Settlement. This includes issues related to the treatment of coal ash basin closures and remediation cost in future general rate cases.

As noted in the Commission's Order, the CCR Settlement does not involve a contemporaneous cost recovery mechanism which could be of substantial benefit to ratepayers as well as to DEC. I am of the opinion that a properly structured cost recovery mechanism would be far preferable to the “spend-defer-recover” method in the CCR Settlement Agreement.

/s/ Commissioner Floyd B. McKissick, Jr.
Commissioner Floyd B. McKissick, Jr.